Progress

2004
PROGRESS ENERGY TRUST
ANNUAL REPORT TO
UNITHOLDERS

2004 ANNUAL REPORT TO UNITHOLDERS

ANNUAL GENERAL MEETING

TUESDAY, APRIL 26TH, 2005 AT 3:30 PM
DEVONIAN ROOM, CALGARY PETROLEUM CLUB
CALGARY, ALBERTA

TORONTO STOCK EXCHANGE TRADING SYMBOLS

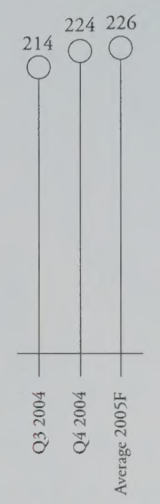
Progress Energy Trust – PGX.UN
Progress Energy Ltd. Exchangeable Shares – PGE
Progress Energy Trust Convertible Debentures – PGX.DB

PROGRESS ENERGY TRUST

is a Calgary based, natural gas focused trust targeting sustainable production and reserves per trust unit through the utilization of its technical capability and capital investment efficiencies. Primary operating areas include the deep basin of northwest Alberta and the foothills and plains regions of northeast British Columbia.

2004 ACCOMPLISHMENTS PROGRESS ENERGY LTD.

- Amalgamated Progress Energy Ltd. and Cequel Energy Inc. to create Progress Energy Trust
- Drilled 37.5 net wells with an 89% success rate
- Achieved finding and development costs of $9.00 per boe proved plus probable and $11.13 per boe proved
- Retained our technical and financial people through the transition



PRODUCTION
(boe per day per million shares)

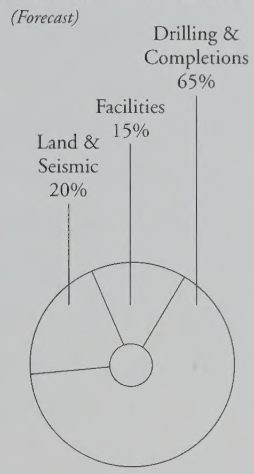
PROGRESS ENERGY TRUST

PGX.UN 2004

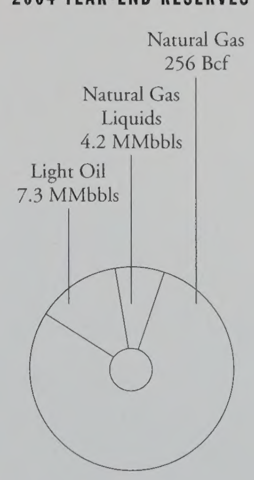
ACCOMPLISHMENTS SINCE INCEPTION AS PROGRESS ENERGY TRUST IN JULY 2004

- Drilled 15.7 net wells with a 100% success rate as a Trust
- Production averaged 17,835 barrels of oil equivalent per day; 79% natural gas
- Year end reserves equal 54.3 million barrels of oil equivalent on a proved plus probable basis yielding a reserve life index of 8.1 years
- Operating Netbacks averaged $25.47 per barrel of oil equivalent – operating costs averaged $5.68 per barrel of oil equivalent
- Distributed $0.14 per trust unit per month or $0.84 per trust unit since the transformation to a trust
- Year end total debt to fourth quarter annualized cash flow was approximately 1.0 times

2005 CAPITAL INVESTMENT
(Forecast)



2004 YEAR-END RESERVES



To Fellow Unitholders 2004 was a year of transformation for Progress, our unitholders and employees. We began the year as a growth-oriented junior exploration company and ended the year as a sustainability-focused energy trust. Our corporate structure has evolved but our primary objective remains unchanged – create unitholder value on a per unit basis. As an energy trust, this philosophy is simply imbedded in a new, more efficient corporate structure that focuses on applying our technical competencies and capital efficiencies to maintain or modestly grow production and reserves on a per unit basis through the drill bit.

In July, we completed the business combination with Cequel Energy Inc., an energy company with a similar value creation philosophy. Both teams had an established track record of growing cash flow, production and reserves on a per share basis while building a portfolio of assets in focused, highly-desirable operating regions – Progress in northeast British Columbia and Cequel in northwest Alberta.

The business combination brought together the high-quality, development-rich, lower risk assets of both companies into Progress Energy Trust. The balance of the assets, largely exploration in nature, created two new junior exploration companies, ProEx Energy and Cyries Energy, both of which the Trust has an exposure to through joint ownership properties and farm-out arrangements.

Our motive was to transform Progress into a sustainable trust – one that maintains or modestly grows its production and reserves underpinning every unit while generating a stable stream of cash distributions for unitholders.

We believe a sustainability model requires several characteristics – a stable, concentrated production base; a low and flattening corporate decline curve; sector leading capital efficiencies; strong cash flow generating capability; and a consistent stream of cash distributions.

As we transitioned from being a high-growth junior exploration company to a sustainable trust, our production base has stabilized in the range of 18,500 barrels of oil equivalent per day. Having a substantially larger production base or being solely focused on growth via acquisition creates challenges to the sustainability model because of the competition for limited opportunities in the Western Canadian Sedimentary Basin. Although our main focus remains on internally generated opportunities, we will continue to pursue select acquisitions which enhance and strengthen our overall asset base.

Our corporate decline rate percentage continues to trend downward as we increase our weighting in tight gas, resource based production and reserves. At the inception of the Trust, initial declines were high from the flush production of two high-growth junior exploration companies. It will continue to flatten as the production

OUR PRIMARY OBJECTIVE REMAINS UNCHANGED – CREATE UNITHOLDER VALUE ON A PER UNIT BASIS.

A FORMULA FOR SUSTAINABILITY

PROGRESS

PROGRESS ENERGY TRUST WAS FORMED TO PURSUE A TECHNICALLY FOCUSED AND DISCIPLINED APPROACH TO LONG-TERM SUSTAINABILITY ON A PER UNIT BASIS

matures, consistent with the typical profile of tight gas wells.

Our capital efficiencies continue to rank near the top of the sector because of the depth and quality of our drilling inventory and the ability of our technical people to successfully execute our program. We are continually high grading our portfolio of opportunities and focusing on drilling the best locations. Replicating our historical capital efficiencies also means we can be patient and disciplined about acquisition opportunities, considering only those assets that enhance the overall quality of our asset base.

Our asset base is, by design, very focused. The play types we pursue suit our technical strengths in tight, multi-zone natural gas and light oil exploration and development. Our three key operating regions; the Deep Basin of northwest Alberta; the Fort St. John plains; and, the northeast British Columbia shallow foothills, represent approximately 85 percent of our asset base. Each region has similar characteristics – a steady production profile, high netbacks, a large undeveloped land base, a deep inventory of repeatable drilling prospects and opportunities to further consolidate and capture upside through land or asset acquisitions.

Our technical focus remains one of the distinguishing features of our Trust. Through the transition to a Trust, we have retained our technical and financial staff – important contributors to the success at predecessor companies. At the inception of the Trust, we invited all of our staff to become unitholders through a private placement. Our intent was clear – align our interests with that of our unitholders. All employees chose to invest in Progress and become unitholders and today the Trust is 13 percent owned by employees, management and directors.

OPERATIONAL ACHIEVEMENTS Since inception, we have continued to build our land base by acquiring additional acreage in our key operating regions. In aggregate, the Trust holds nearly 600,000 net undeveloped acres representing one of the largest undeveloped land bases among energy trusts when measured on a unit of production. Our drilling inventory contains approximately 200 locations, or in excess of two years of inventory.

Our ability to add reserves very efficiently through the drill bit was highlighted by our strong finding and development costs in 2004. Total exploration and development capital in 2004 was $106.4 million which represents the capital invested by the Progress technical team for the period as Progress Energy Ltd. from January to July and as Progress Energy Trust from July to December. This capital investment resulted in proved plus probable finding and development (F&D) costs of $9.00 per boe while proved F&D costs were $11.13 per boe including changes in future development capital. We expect these will be industry leading reserve addition costs.

Year end proved plus probable reserves were 54.3 million boe while proved reserves were 42.4 million boe. The Trust's proved plus probable reserve life index is 8.1 years or 6.3 years proved with proved undeveloped reserves representing only 7 percent of total proved reserves.

THROUGH THE TRANSFORMATION TO A TRUST, WE HAVE RETAINED OUR TECHNICAL AND FINANCIAL STAFF – IMPORTANT CONTRIBUTORS TO THE SUCCESS AT PREDECESSOR COMPANIES.


ENERGY
PROGRESS IS A NATURAL GAS FOCUSED ENERGY TRUST WITH AN ABUNDANT
INVENTORY OF DRILLING OPPORTUNITIES

FINANCIAL ACHIEVEMENTS For the period from July to December 2004, cash flow from operations was $77.7 million or $0.95 per unit diluted. Our cash flow generating capability is enhanced by the high heat content of our natural gas and low operating cost structure providing Progress with one of the strongest netbacks in the industry. Our target payout ratio is in the range of 70 percent with the balance of the cash flow being reinvested to hold production steady. We have distributed $55.7 million, or $0.14 per month, to unitholders since inception in July 2004.

Although we cannot control gas prices, we continue to use hedging to manage our exposure to inherent volatility in natural gas prices and provide greater certainty and stability of our revenue stream. We will typically use a series of collars and swaps to hedge up to a maximum of 50 percent of our before royalty production.

We remain in a very good financial position with total debt to fourth quarter annualized cash flow at year-end of approximately 1.0 times. Subsequent to year end, in February 2005, we issued $100 million of convertible debentures to fix the interest rate and term out a portion of our debt at 6.75 percent until June 30, 2010, providing further financial flexibility.

OUTLOOK The outlook for the energy sector remains positive. Underlying changes in the North American natural gas supply and demand balance continue to evolve and are likely to hold natural gas prices at historically high levels, although with increased volatility. Fundamentally, natural gas supply in North America remains tight with continuing year-over-year declines in production. New natural gas discoveries tend to be smaller and incremental production tends to have higher initial declines.

Oil prices remain at historically high levels because of a myriad of factors including Asian demand growth and political unrest in producing countries which appears to have eroded spare capacity leading to general expectations for stronger oil prices.

On behalf of the Board and the management team, we extend our appreciation to all of our employees for their continued diligence in creating unitholder value through the transition and early in our life as a trust. Our people, and the technical know-how they bring to the job everyday, are critical to our success. They are innovative and creative people who are closely aligned with our unitholders through direct unit ownership.

To our unitholders, we thank you for your continued support.

On behalf of the Board of Directors

David D. Johnson
Executive Chairman

Michael R. Culbert
President

February 22, 2005

DAVID JOHNSON, EXECUTIVE CHAIRMAN (RIGHT); MICHAEL CULBERT, PRESIDENT (LEFT)

TRUST

PROGRESS SEEKS TO GENERATE A STEADY STREAM OF DISTRIBUTIONS WHILE MAINTAINING PRODUCTION PER UNIT OVER AN EXTENDED PERIOD OF TIME.

Progress Energy Trust operates in three primary regions in the Western Canadian Sedimentary Basin – the Deep Basin of northwest Alberta; the plains region of Fort St. John and the shallow foothills of northeast British Columbia. These regions comprise over 80 percent of the Trust's reserves and production and provide multi-zone prospects in areas with year round access and existing gathering and processing facilities. The balance of the Trust's assets are located in central Alberta and southeast Saskatchewan.

The Trust holds nearly 600,000 net acres of undeveloped land making it one of the largest landholders on the basis of net acres of undeveloped land per barrel of production among energy trusts. The Trust operates the majority of the properties in which it has an interest in order to control the pace of development and apply its capital and operating cost efficiencies.

Capital investment in 2005 is forecast to be approximately $70 million to $75 million, targeting a 40 to 45 net well drilling program.

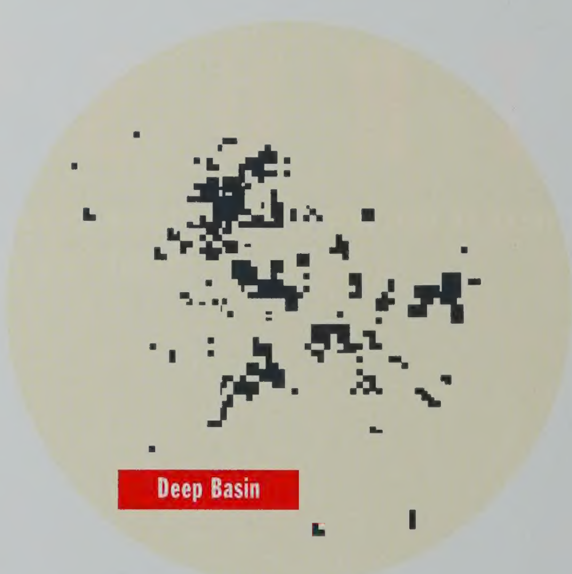
DEEP BASIN REGION, NORTHWEST ALBERTA

The Trust's main interests in the Deep Basin are located immediately south of the city of Grande Prairie. The region includes its primary producing properties at Gold Creek and Karr, with additional producing interests in the Economy Creek, Elmworth, Wapiti and Kakwa areas. The Deep Basin region represents approximately 45 percent of the Trust's reserves and production.

The Trust holds approximately 164,000 net undeveloped acres in this region and maintains an extensive portfolio of development drilling locations. It also maintains an exposure to further upside through joint ownership arrangements with Cyries Energy in the area.

The geology is characterized by its medium depth, multi-zone, gas prone opportunities with well developed infrastructure. Since inception in July 2004, the Trust achieved a 100-percent success rate on its 8 gross wells (3.6 net) drilling program.

The region has very well developed infrastructure which ensures that new production can be brought on-stream quickly and efficiently. Operating cost efficiencies are enhanced through the Trust's 27 percent interest in the Gold Creek gas plant and an average 12 percent interest in the Karr gas plant.



ART MACNICHOL, VICE PRESIDENT FINANCE AND CHIEF FINANCIAL OFFICER (LEFT); GREG KIST, VICE PRESIDENT INVESTOR RELATIONS (RIGHT)

NORTHWEST ALBERTA
DEEP BASIN
164,000 net undeveloped acres
~45%
of production

FORT ST. JOHN PLAINS
105,000 net undeveloped acres
~20%
of production

NORTHEAST B.C.
SHALLOW FOOTHILLS
62,000 net undeveloped acres
~20%
of production

PROGRESS CAN REMAIN OPPORTUNISTIC ABOUT ACQUISITIONS BECAUSE OF THE DEPTH OF ITS DRILLING INVENTORY AND ITS STRONG CAPITAL EFFICIENCIES.

QUALITY

FORT ST. JOHN PLAINS REGION, NORTHEAST BRITISH COLUMBIA

Progress has a locally dominant position in the Fort St. John Plains region, located in close proximity to the city of Fort St. John on the northern flank of the Peace River. This all-weather access region represents approximately 20 percent of the Trust's reserves and production.

The Fort St. John area produces light oil and natural gas from a predictable sequence of porous Cretaceous fluvial derived sands and Triassic aged preserved sand dunes. Up to ten separate and distinct reservoirs can be encountered in a typical 1,200 meter depth well in the Fort St. John exploration area. The Trust holds a significant land position in the region and continues to target property and asset acquisitions, crown land purchases, and farm-ins to further solidify contiguous land blocks.

In 2004, the Trust drilled 3 gross wells (1.5 net). Progress now holds approximately 105,000 net acres of undeveloped land in the area.

Gas production is processed through Duke Energy owned and operated facilities which enables producers to avoid major facility construction in exchange for regulated gathering, processing and transmission fees.

SHALLOW FOOTHILLS, NORTHEAST BRITISH COLUMBIA

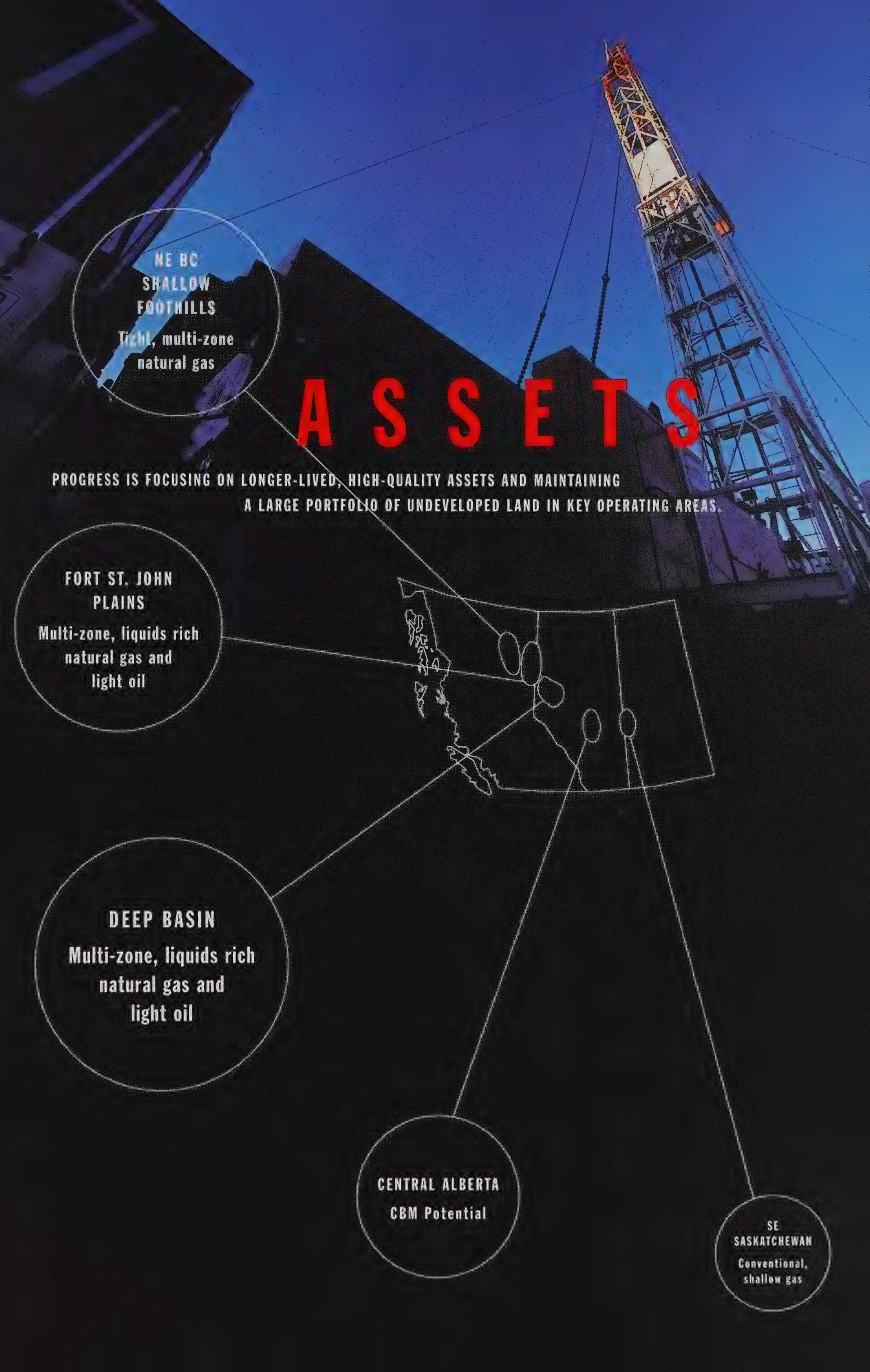
Approximately 100 kilometers northwest of Fort St. John, British Columbia, along the Alaska Highway, is the shallow foothills region. Progress generally holds a 100 percent working interest in the Town and Beg properties and holds a 20 percent working interest in Gundy Creek area. The Trust holds over 62,000 net undeveloped acres of land in this area providing upside from a multi-well program.

The primary targets are the Cretaceous and Triassic sands which were deposited in a series of parallel, gas-filled, fractured anticlines giving rise to large accumulations of gas over a large areal extent. The primary target is the 100-foot thick Halfway formation which is present at typical well depths of approximately 1,800 meters. Three dimensional seismic imaging is used to identify the anticlinal structures. Improving economics and advances in completions technologies have been the primary drivers in opening this tight gas region.

Since inception of the Trust, 10 gross wells (4.4 net) have been drilled with a 100 percent success rate. The foothills represent approximately 20 percent of production and approximately 25 percent of reserves.

ASSETS

PROGRESS IS FOCUSING ON LONGER-LIVED, HIGH-QUALITY ASSETS AND MAINTAINING A LARGE PORTFOLIO OF UNDEVELOPED LAND IN KEY OPERATING AREAS.



FAST-PACED, TARGET-ORIENTED TEAM

Progress Energy Trust

A HIGHLY SKILLED AND CAPABLE TEAM OF PROFESSIONALS The decision to convert to a trust involved careful consideration of how to retain our highly skilled and qualified teams – professionals who have made a significant contribution to our historical success at predecessor companies. By maintaining our technical and financial staff we can more actively manage our asset base and generate new concepts and ideas from within.

At the inception of the Trust in July of 2004, the Progress team was joined by an equally capable and qualified team from Cequel. The net result is a small, fast-paced, target-oriented organization consisting of approximately 75 people. They have the geological, engineering and financial skills and experience to create unitholder value from internal opportunities.

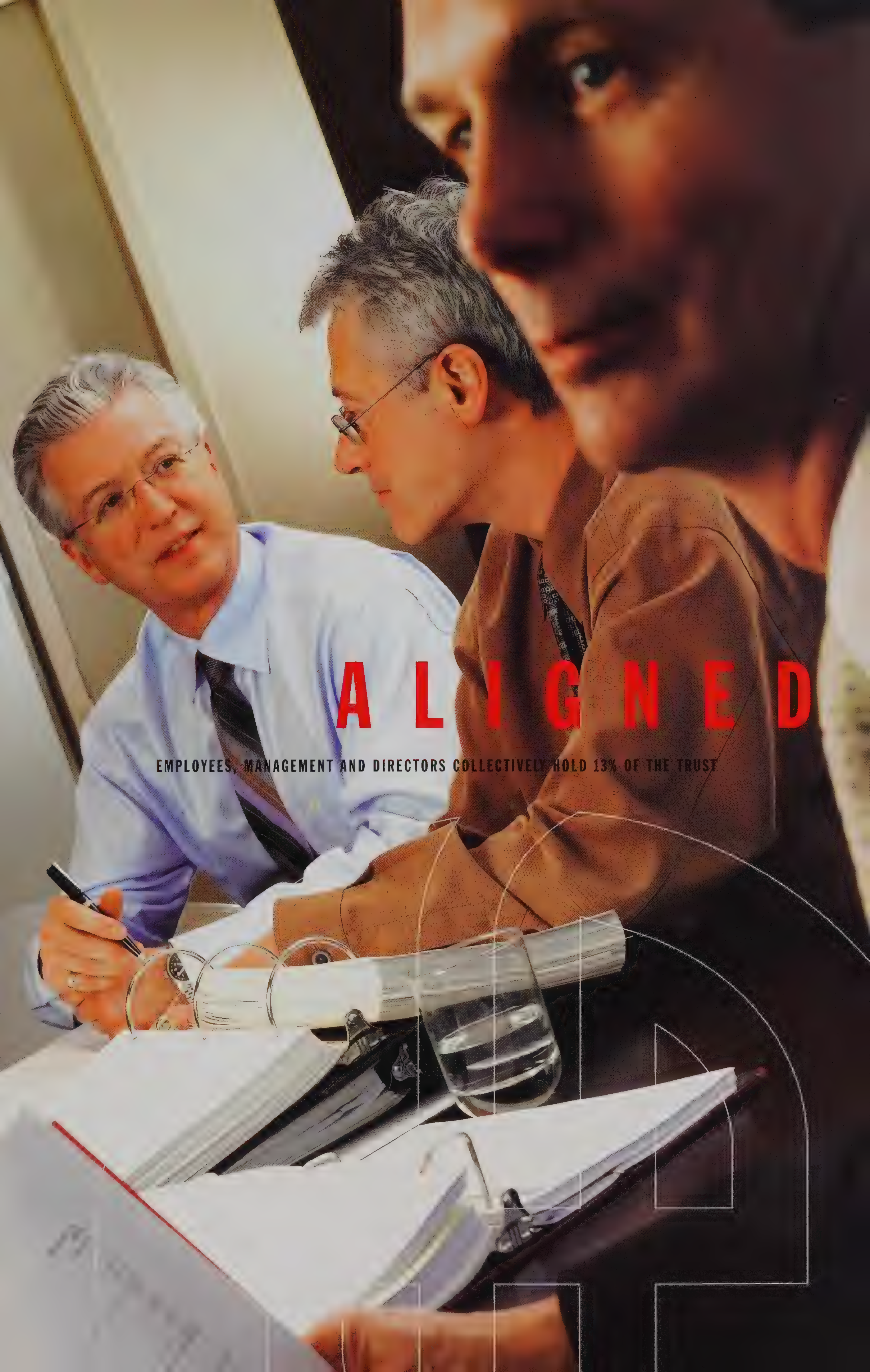
Our desire to align our interests with that of our unitholders is clear. All of our staff participated in a private placement at the inception of the Trust. Today employees, management and directors own approximately 13 percent of the fully diluted units. This is direct unit ownership rather than options or compensation through third-party management contracts. Longer term incentives are in the form of a performance unit incentive plan which rewards per unit value creation and also measures long-term total unitholder return against a peer group of companies.

STRONG GOVERNANCE PRACTICES The Board of Directors and the management team work very closely to realize Progress' potential. The Board and management are committed to maintaining a high level of corporate governance as reflected in its organization, responsibilities and timeliness and thoroughness of its disclosure. Board and committee responsibilities can be found in the Information Circular on our website at www.progressenergy.com or on SEDAR at www.sedar.com.

Technical Services Committee In conjunction with the Plan of Arrangement, the Trust has entered into a Technical Services Agreement with ProEx Energy Ltd. (ProEx), whereby the Trust provides the manpower required for administrative and technical services. The Trust and ProEx have interests in joint properties and undeveloped lands. These properties and undeveloped lands are governed by standard industry agreements. The Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will govern the management of joint lands in specifically identified areas of interest.--

To ensure good governance practices, both the Trust and ProEx have established independent committees of their respective Boards of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

LEFT TO RIGHT: STEVEN ALLAIRE, SENIOR VICE PRESIDENT; DANIEL TOPOLINSKY, VICE PRESIDENT EXPLORATION; NEIL SAMIS, VICE PRESIDENT PRODUCTION


ALIGNED
EMPLOYEES, MANAGEMENT AND DIRECTORS COLLECTIVELY HOLD 13% OF THE TRUST

RESULTS DISCUSSION

Progress Energy Trust

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
bbls	barrels
bbls/d	barrels per day
mbbls	thousand barrels
mmbbls	million barrels
NGL	natural gas liquids

Natural Gas

mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
mmbtu	million British Thermal Units
bcf	billion cubic feet
GJ	gigajoule

AECO	Intra-Alberta Nova Inventory Transfer Price (NIT net price of natural gas)
API	an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale. Liquid petroleum with a specified gravity of 28 API or higher is generally referred to as light crude oil
boe	barrel of oil equivalent of natural gas on the basis of 1 BOE for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
boe/d	barrel of oil equivalent per day
m^3	cubic metre
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade
$MM	millions of dollars

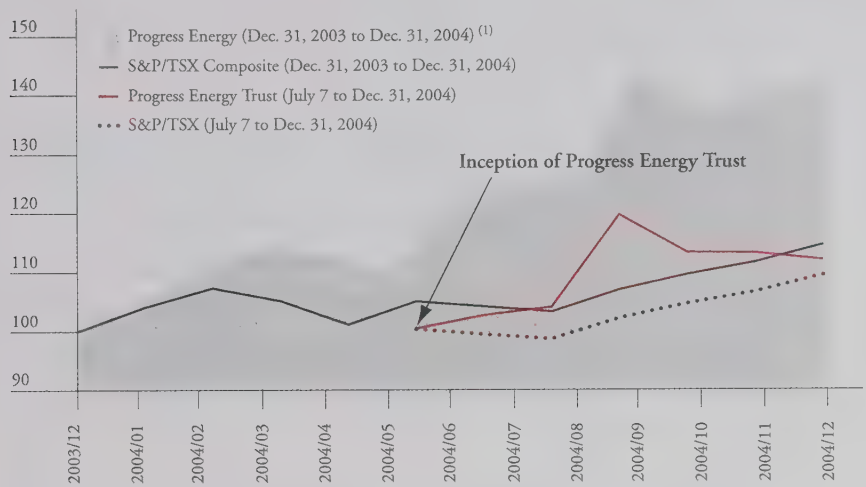
Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

RESULTS

OUR CORPORATE STRUCTURE HAS EVOLVED BUT OUR PRIMARY OBJECTIVE REMAINS UNCHANGED – CREATE UNITHOLDER VALUE ON A PER UNIT BASIS.

TOTAL RETURN TO SHAREHOLDERS/UNITHOLDERS – 2004

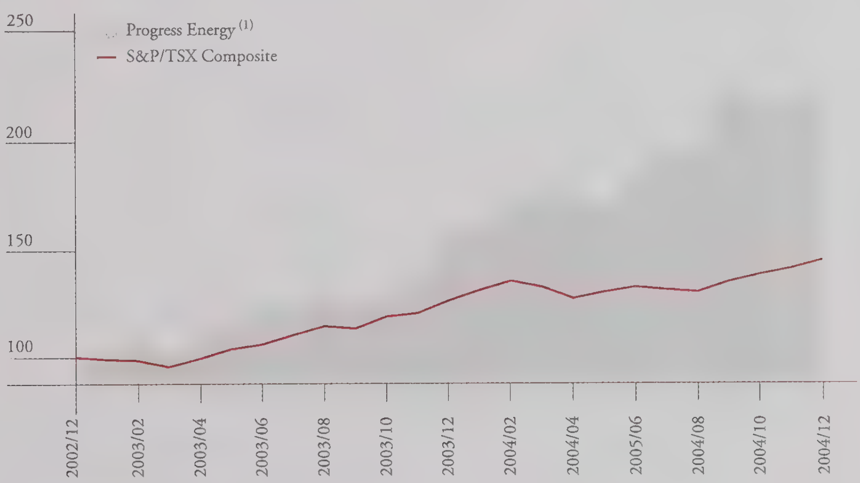
(December 30, 2003 = 100 for Progress Energy)
(July 7, 2004 = 100 for Progress Energy Trust)



(1) Progress Energy performance is adjusted for ProEx and Cyries for the period from July 7 to December 31, 2004

TOTAL RETURN TO SHAREHOLDERS – 2003/2004

(December 31, 2002 = 100)



(1) Progress Energy performance is adjusted for ProEx and Cyries for the period from July 7 to December 31, 2004

The corporate reserves were prepared by the independent engineering firm of Gilbert Laustsen Jung Associates Ltd ("GLJ") in 2004 as well as prior years back to 2001. Reserves included herein are stated on a company interest basis (before royalty burdens and including royalty interests) unless noted otherwise. All reserves information has been prepared in accordance with National Instrument ("NI") 51-101. In addition to the detailed information disclosed in this annual report, more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) is included in the Trust's Annual Information Form ("AIF").

- Total proved reserves at December 31, 2004 increased 84 percent to 42.4 million boe compared to 23.1 million boe in 2003.
- Total proved plus probable reserves at December 31, 2004 increased 86 percent to 54.3 million boe compared to 29.2 million boe in 2003.

FORECASTED PRICES AND COSTS
Summary of Oil and Gas Reserves
Company Interest

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	**2004 BOE**	2003 BOE
	(mbbls)	*(mbbls)*	*(bcf)*	*(mmboe)*	*(mboe)*
Proved					
– Developed Producing	4,379	2,977	168.65	**35.50**	16.54
– Developed Non-Producing	614	228	18.18	**3.88**	3.07
– Undeveloped	300	150	15.65	**3.06**	3.49
Total Proved	5,293	3,355	202.49	**42.44**	23.09
Probable	1,968	851	53.42	**11.84**	6.12
Total Proved Plus Probable	7,262	4,206	255.90	**54.28**	29.21

Note: May not add due to rounding

Net Present Value of Reserves – Forecasted Prices and Costs

	Undiscounted	Discounted at 8%	Discounted at 10%	Discounted at 12%
	($MM)	*($MM)*	*($MM)*	*($MM)*
Proved				
– Developed Producing	785.43	530.76	496.10	466.98
– Developed Non-Producing	79.56	48.94	44.34	40.46
– Undeveloped	58.36	32.55	29.14	26.31
Total Proved	923.35	612.25	569.58	533.75
Probable	273.58	125.53	109.58	97.05
Total Proved Plus Probable	1,196.93	737.78	679.16	630.800

Note: May not add due to rounding

Pricing Assumptions – Forecasted Prices and Costs

The January 1, 2005 pricing forecasts presented below have been prepared by GLJ. These prices have been utilized in determining the reserves and cash flow forecasts.

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO	Natural Gas Sumas Spot	Inflation Rate
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/MMBtu)*	*($US/MMBtu)*	*(%/Year)*
2005	42.00	50.25	6.60	5.55	2.0
2006	40.00	47.75	6.35	5.40	2.0
2007	38.00	45.50	6.15	5.25	2.0
2008	36.00	43.25	6.00	5.10	2.0
2009	34.00	40.75	6.00	5.10	2.0
2010	33.00	39.50	6.00	5.10	2.0
2011	33.00	39.50	6.00	5.10	2.0
2012	33.00	39.50	6.00	5.10	2.0
2013	33.50	40.00	6.10	5.15	2.0
2014	34.00	40.75	6.20	5.25	2.0
2015	34.50	41.25	6.30	5.35	2.0
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

CONSTANT PRICES AND COSTS

Net Present Value of Reserves – Constant Prices and Costs

	Undiscounted	Discounted at 8%	Discounted at 10%	Discounted at 12%
	($MM)	*($MM)*	*($MM)*	*($MM)*
Proved				
– Developed Producing	858.42	580.09	540.86	507.74
– Developed Non-Producing	91.60	56.03	50.66	46.12
– Undeveloped	64.32	36.88	33.10	29.95
Total Proved	1,014.34	673.01	624.63	583.81
Probable	287.00	136.94	119.85	106.27
Total Proved Plus Probable	1,301.34	809.95	744.48	690.08

Note: May not add due to rounding

Pricing Assumptions – Constant Prices and Costs

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO	Natural Gas Sumas Spot	Inflation Rate
	($US/bbl)	*($Cdn/bbl)*	*($Cdn/MMBtu)*	*($US/MMBtu)*	*(%/Year)*
2005	43.45	46.54	6.79	5.50	0

2004 RESERVE RECONCILIATION

Reconciliation of Company Interest Reserves by Principal Product Type

Forecast Prices and Costs

	Light and Medium Crude	Natural Gas	Natural Gas Liquids	BOE
	(mbbl)	*(bcf)*	*(mbbl)*	*(mmboe)*
Proved Producing				
Opening Balance	3,533	72.93	853	16.54
Exploration Discoveries	74	4.18	69	0.84
Drilling Extensions	462	15.04	135	3.10
Infill Drilling	26	5.23	48	0.95
Improved Recovery	296	14.21	386	3.05
Technical Revisions	(83)	18.86	(33)	3.03
Acquisitions	1,734	68.13	1,913	15.00
Dispositions	(775)	(7.17)	(95)	(2.06)
Production	(855)	(22.77)	(298)	(4.95)
Closing Balance	4,414	168.65	2,977	35.50
Total Proved				
Opening Balance	4,368	105.24	1,185	23.09
Exploration Discoveries	74	5.96	134	1.20
Drilling Extensions	655	23.03	206	4.70
Infill Drilling	79	8.34	60	1.53
Improved Recovery	40	8.15	250	1.65
Technical Revisions	120	3.42	(194)	0.50
Acquisitions	1734	80.66	2,127	17.30
Dispositions	(877)	(9.55)	(115)	(2.58)
Production	(855)	(22.77)	(298)	(4.95)
Closing Balance	5,338	202.48	3,354	42.44
Proved Plus Probable				
Opening Balance	5,894	131.05	1,472	29.21
Exploration Discoveries	89	8.65	202	1.73
Drilling Extensions	1,248	30.99	273	6.69
Infill Drilling	111	8.73	69	1.64
Improved Recovery	69	9.49	295	1.95
Technical Revisions	(157)	2.32	(241)	(0.01)
Acquisitions	2122	100.15	2,588	21.40
Dispositions	(1,100)	(12.74)	(154)	(3.38)
Production	(855)	(22.77)	(298)	(4.95)
Closing Balance	7,422	255.90	4,206	54.28

Note: May not add due to rounding

2004 FINDING AND DEVELOPMENT COSTS (F&D) and FINDING, DEVELOPMENT AND NET ACQUISITION COSTS (FD&A)

- Finding and development costs associated with the 2004 exploration and development program, including revisions and the change in future capital were $11.13 per proved boe and $9.00 per proved plus probable boe.

- Finding, development and acquisition costs associated with the 2004 capital program, including revisions and the change in future capital were $20.24 per proved boe and $16.44 per proved plus probable boe. This primarily reflects the Cequel Energy Inc. ("Cequel") acquisition.

	Capital Expenditures	Proved Reserve Additions	Proved Costs	Proved Plus Probable Reserve Additions	Proved Plus Probable Costs
	($ millions)	*(mmboe)*	*($/boe)*	*(mmboe)*	*($/boe)*
Proved exploration and development program F&D after revisions	106.63	9.58	11.13	n/a	n/a
Proved plus probable exploration and development program F&D after revisions	108.03	n/a	n/a	12.00	9.00
Net acquisition/disposition activity	385.29	14.72	n/a	18.01	n/a
Total 2004 proved FD&A costs including future development costs	491.92	24.30	20.24	n/a	n/a
Total 2004 proved plus probable FD&A costs including future development costs	493.32	n/a	n/a	30.01	16.44

Reconciliation of Changes in Future Development Capital:

In accordance with NI 51-101, the capital used to calculate F&D costs has been adjusted to account for the change in future development capital. For that reason the capital may differ between the proved case and the proved plus probable case.

($ millions)	Proved	Change	Proved Plus Probable	Change
2004	18.14	(1.78)	27.11	(0.38)
2003	19.92		27.49	

RESERVE LIFE INDEX

The Trust's reserve life index using annualized fourth quarter production is 6.3 years proved and 8.1 years proved plus probable. Reserve life calculated using annualized fourth quarter production may be more reflective of reserve life due to the active capital program and the level of new production added in the fourth quarter.

	2004 Using Annualized Q4 Production	**2004** Using 2005 GLJ Forecast Production	2003 Using Annualized Q4 Production	2003 Using 2004 GLJ Forecast Production
Production *(mmboe)*	**6.704**	**6.821**	3.100	3.362
Proved Reserves *(mmboe)*	**42.44**	**42.44**	23.09	23.09
Proved Reserve Life Index *(years)*	**6.3**	**6.2**	7.4	6.9
Production *(mmboe)*	**6.704**	**7.221**	3.100	3.705
Proved Plus Probable Reserves *(mmboe)*	**54.28**	**54.28**	29.21	29.21
Proved Plus Probable RLI *(years)*	**8.1**	**7.5**	9.4	7.9

RESERVE REPLACEMENT

The Trust's 2004 exploration and development program replaced production by a factor of 1.9 times on a proved basis and 2.4 times on a proved plus probable basis. The total capital program including the Cequel acquisition replaced production by a factor of 4.9 times on a proved basis and 6.1 on a proved plus probable basis.

	2004
Production *(mmboe)*	**4.95**
Proved reserve additions not including acquisitions and divestments *(mmboe)*	**9.58**
Proved replacement ratio	**1.9**
Proved reserve additions including acquisitions and divestments *(mmboe)*	**24.3**
Proved replacement ratio	**4.9**
Proved plus probable reserve additions not incl. acquisitions and divestments *(mmboe)*	**12.00**
Proved plus probable replacement ratio	**2.4**
Proved plus probable reserve additions incl. acquisitions and divestments *(mmboe)*	**30.02**
Proved plus probable replacement ratio	**6.1**

RECYCLE RATIO

The recycle ratio is a measure for evaluating the effectiveness of a company's reinvestment program. The ratio measures the efficiency of capital investment. It accomplishes this by comparing the operating netback per barrel of oil equivalent to that year's reserve finding and development costs.

	2004
Operating netback *($/boe)*	24.41
Proved finding and development costs after revisions of prior periods and including the change in future development capital *($/boe)*	11.13
Proved recycle ratio	2.2
Proved plus probable finding and development after revisions of prior periods and including the change in future development capital *($/boe)*	9.00
Proved plus probable recycle ratio	2.7

NET ASSET VALUE – DISCOUNTED AT 10 PERCENT

The Trust's net asset value is measured with reference to the present value of future estimated net cash flows from reserves estimates prepared by GLJ, the independent reserve engineers, and including land, seismic data, adjustments for working capital deficiency and bank debt at year end. This calculation can vary significantly depending on the natural gas and oil price assumptions used by GLJ. This calculation does not represent a "going-concern" value since it only assumes the reserves contained in the GLJ report.

Progress' net asset value per trust unit at December 31, 2004 was $8.13 per trust unit using GLJ constant prices and $7.33 per trust unit using GLJ forecasted prices.

($ thousands)	2004	2004
	Constant Price	Forecasted Price
Proved plus probable reserve value [1]	744,477	679,160
Undeveloped acreage [2]	75,000	75,000
Seismic [3]	20,000	20,000
Working capital deficiency	(37,821)	(37,821)
Bank debt	(133,722)	(133,722)
Net asset value	667,934	602,617
Units outstanding	82,189	82,189
Net asset value per unit	$ 8.13	$ 7.33

[1] *Reserve values are based on before tax estimates of future cash flows as evaluated by our independent qualified reserve evaluators using their future commodity price forecast as presented in the pricing assumptions on page 17.*

[2] *Internal estimate based on land sales values as reported in the Daily Oil Bulletin.*

[3] *Seismic inventory values are an estimate of replacement value.*

The following discussion and analysis of financial results is dated February 21, 2005 and is to be read in conjunction with the accompanying audited consolidated financial statements for the years ended December 31, 2004 and 2003. The financial data presented has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). The reporting and the measurement currency is the Canadian dollar.

Management uses cash flow from operations (before changes in non-cash working capital) ("cash flow") to analyze operating performance and leverage. The term distributable cash is also used to present the amount of cash that the Trust distributes to unitholders. Neither distributable cash nor cash flow presented have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Distributable cash and cash flow as presented are not intended to represent operating profit for the period nor should they be viewed as an alternative to operating profit, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. The reconciliation between net earnings and cash flow can be found in the consolidated statements of cash flows in the year end audited consolidated financial statements. All references to cash flow throughout the MD&A are based on cash flow before changes in non-cash working capital.

Plan of Arrangement – Transformation to a Trust

On July 2, 2004 Progress Energy Ltd. and Cequel Energy Inc. ("Cequel") amalgamated to create Progress Energy Trust ("Progress" or the "Trust") and two publicly listed, exploration-focused companies, ProEx Energy Ltd. ("ProEx") and Cyries Energy Inc. ("Cyries"), pursuant to a Plan of Arrangement ("Arrangement"). The Arrangement resulted in Progress Energy Ltd. shareholders receiving one trust unit or exchangeable share of the Trust and 0.2 of a share in each of ProEx and Cyries. Cequel shareholders received 0.695 trust units or exchangeable shares of the Trust and 0.139 of a share in each of ProEx and Cyries. Upon completion of the Arrangement, 65.4 million trust units and 16.0 million exchangeable shares were outstanding. As at February 21, 2005 there were 67.8 million trust units and 13.8 million exchangeable shares outstanding. An assessment of the Trust's unitholder base indicates that approximately 30 percent of the trust units are currently held by non-residents of Canada.

The Arrangement resulted in the Trust owning approximately 90 percent of the combined producing assets of Progress Energy Ltd. and Cequel. The remainder of the properties of Progress Energy Ltd. and Cequel were transferred to ProEx and Cyries, respectively, consisting of certain prospective natural gas weighted assets and undeveloped land. As a result of the Arrangement the Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will govern the management of the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx.

The conversion of Progress Energy Ltd. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements for 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Progress Energy Ltd. The year ended December 31, 2004 reflect the results of operations and cash flows of Progress Energy Ltd. and its subsidiaries for the period January 1 to July 1, 2004 and the results of operations and cash flows of the Trust and its subsidiary for the period July 2 to December 31, 2004. The comparative figures are the results of Progress Energy Ltd. and its subsidiaries. Due to the conversion into an energy trust, certain information included in the MD&A for prior periods may not be directly comparable.

The term "units" has been used to identify both the trust units and exchangeable shares of the Trust issued on or after July 2, 2004 as well as the common shares of the corporation outstanding prior to the conversion on July 2, 2004.

Description of Business

Progress is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The Trust's unitholders and shareholders are the sole beneficiaries of the Trust. The trust structure allows individual unitholders to participate in the cash flow of the business. Cash flow is realized from the Trust's ownership of natural gas and petroleum properties and related facilities.

Progress is a Calgary based, natural gas focused, trust targeting sustainable production and reserves per trust unit through utilization of its technical capability and capital investment efficiencies. Primary operating areas include the deep basin of northwest Alberta and the shallow foothills and plains regions of northeast British Columbia. Trust units of Progress trade on the Toronto Stock Exchange ("TSX") under the symbol PGX.UN. Exchangeable shares and 6.75 percent convertible unsecured subordinated debentures of Progress trade on the TSX under the symbols PGE and PGX.DB respectively.

OPERATING SUMMARY

In accordance with Canadian industry practice, production volumes, reserve volumes and revenues are reported on a Trust interest basis (working interest plus royalty interest), before deduction of Crown and other royalties, unless otherwise indicated. The Trust's results of operations are dependent on production volumes of natural gas, crude oil and natural gas liquids and the prices received for this production. Prices for these commodities have shown significant volatility during recent years and are determined by supply and demand factors, including weather and general economic conditions and changes in the Canadian/US currency exchange rate.

In this MD&A, production and reserves information may be presented on a "barrel of oil equivalent" or "boe" basis with six thousand cubic feet ("mcf") of natural gas being equivalent to one barrel of crude oil or natural gas liquids. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the well-head.

Production

	2004	2003	% Change
Daily Production			
Natural gas *(mcf/d)*	**62,221**	28,936	115%
Crude oil *(bbls/d)*	**2,335**	2,337	0%
Natural gas liquids *(bbls/d)*	**814**	299	172%
Total daily production *(boe/d)*	**13,519**	7,459	81%
Natural gas as a % of total production	**77%**	65%	

Production in 2004 averaged 13,519 boe per day consisting of 62,221 mcf per day of natural gas, 2,335 bbls per day of crude oil and 814 bbls per day of natural gas liquids. This compares favorably to average production of 7,459 boe per day for the same period in 2003 mainly due to the Cequel acquisition and successful drilling at the shallow foothills, northeast British Columbia core area, partially offset by the transfer of assets to ProEx as part of the Arrangement. The Trust's production portfolio in 2004 was weighted 77 percent to natural gas, 17 percent to crude oil and six percent to natural gas liquids.

The Trust's 2004 fourth quarter production averaged 18,368 boe per day, comprising of 86,998 mcf per day of natural gas, 2,475 boe per day of crude oil and 1,394 boe per day of natural gas liquids.

Management anticipates production to average between 18,500 and 19,500 boe per day in 2005.

Production Reconciliation

	Production Equivalent
	(boe/d)
Production fourth quarter 2003	8,483
Decline on base production	(1,660)
Exploration program production additions during 2004	5,666
Decline on new 2004 production	(1,726)
2004 acquisition of Cequel	8,753
2004 transfer to ProEx	(1,003)
2004 dispositions	(145)
Production fourth quarter 2004	18,368

The 2004 exploration program produced production additions for the year of 5,666 boe per day. With a capital expenditure program of $106.4 million this resulted in production being added at a cost of $18,783 per boe per day. The production additions were mainly the result of successful drilling results in the shallow foothills of northeast British Columbia.

The Cequel acquisition accounted for all production additions through acquisitions during the year.

The Trust continues to divest non-core assets. During the year the Trust transferred assets to ProEx as part of the Arrangement and sold several minor properties in southwestern Saskatchewan, reducing 2004 fourth quarter production compared to 2003 fourth quarter production by 1,148 boe per day.

Key Producing Areas The following table summarizes the Trust's average production by key producing areas for the years ended December 31, 2004 and 2003 and the three months ended December 31, 2004:

Principal Producing Core Areas (boe/d)

	Fourth Quarter 2004	2004	2003	% Change
Fort St. John plains	**2,783**	**3,049**	2,280	34%
Shallow foothills	**2,951**	**2,813**	1,206	133%
Total British Columbia	**5,734**	**5,862**	3,486	68%
Gold Creek	**9,023**	**4,174**		
Gilby	**1,451**	**1,226**	1,305	(6%)
Other	**1,702**	**1,759**	2,059	(15%)
Total Alberta	**12,176**	**7,159**	3,364	113%
Saskatchewan/Manitoba	**458**	**498**	609	(18%)
Total daily production	**18,368**	**13,519**	7,459	81%

Successful drilling in the shallow foothills of northeast British Columbia and the addition of the Gold Creek properties as part of the Cequel acquisition contributed a substantial portion of the production growth during the year.

Pricing and Risk Management

Commodity prices through 2004 remained very robust with West Texas Intermediate ("WTI") crude oil hitting a new record level of US$53.00 per barrel in the fourth quarter and both the US New York Mercantile Exchange ("NYMEX") price and Canadian Alberta Energy Company interconnect with the Nova System ("AECO") prices trading up over $7.00 per MMbtu at times during the year. Continuing political uncertainty and low refined product inventories caused ongoing uncertainties in the crude oil markets with the 2004 WTI price starting the year at US$34.00 per barrel and settling in at US$43.00 to US$48.00 per barrel at year end. Strong oil prices helped support the natural gas prices as storage inventories hit highs in the fall. Reduced demand from space heating due to a warmer than normal winter so far this year has resulted in storage levels remaining at surplus levels in the US and close to normal in Canada.

As we look forward to 2005, we expect to see WTI oil prices remain in the US$40.00 to US$45.00 per barrel range and natural gas at AECO to trade between $6.00 to $7.25 per MMbtu. Progress produces predominantly light oil and high heat content liquids rich natural gas that attract premium prices in the market. This contributes to the Trust's attractive netbacks that are illustrated on the following tables.

Commodity Prices

	2004	2003	% Change
Average Benchmark Prices			
AECO (daily) natural gas *($/mcf)*	**6.51**	6.70	(3%)
WTI crude oil *(US$/bbl)*	**41.40**	31.04	33%
Edmonton par price *(Cdn$/bbl)*	**52.54**	43.16	22%
Exchange rate *(US$/Cdn$)*	**0.7685**	0.7138	8%
Average Realized Prices			
Natural gas – before hedging *($/mcf)*	**7.08**	6.66	6%
Hedging settlements *($/mcf)*	**0.13**	0.07	
Amortization of hedge premiums *($/mcf)*	**(0.03)**	(0.07)	
Amortization of commodity sales contract *($/mcf)* [1]	**0.03**	0.08	
Change in fair value of financial instruments *($/mcf)* [2]	**(0.08)**	–	
Natural gas – after hedging *($/mcf)*	**7.13**	6.74	6%
Crude oil – before hedging *($/bbl)*	**50.72**	39.87	27%
Hedging *($/bbl)*	**(5.05)**	(1.78)	
Amortization of hedge premiums *($/bbl)*	**(0.23)**	(0.13)	
Change in fair value of financial instrument *($/bbl)* [2]	–	0.44	
Crude oil – after hedging *($/bbl)*	**45.44**	38.40	18%
Natural gas liquids *($/bbl)*	**45.40**	33.02	37%

[1] *Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.*

[2] *Change in fair value of financial instrument of ineffective hedges or contracts that did not qualify for hedge accounting.*

Natural Gas Pricing US natural gas prices are typically referenced off NYMEX at Henry Hub, Louisiana while Alberta natural gas is referenced off Nova Inventory Transfer or the AECO Hub and British Columbia natural gas off of Sumas Washington or Station #2 market centers. Virtually all of Progress' natural gas is sold at market prices at one of the Alberta or British Columbia hubs.

Natural Gas Production and Prices by Province

	2004		2003	
	mcfd	*$/mcf*	*mcfd*	*$/mcf*
Alberta	**30,106**	**7.22**	11,559	6.82
British Columbia	**30,762**	**6.97**	16,495	6.64
Saskatchewan and Manitoba	**1,353**	**6.08**	882	4.80
Total production and average sales price [1]	**62,221**	**7.08**	28,936	6.66

[1] *Before the impact of hedging*

Alberta Natural Gas Prices

	2004	2003
NYMEX *(US$/mmbtu 12 month average – last 3 days)*	**6.09**	5.44
Less: AECO basis differential to Henry Hub *(US$/mmbtu)*	**(1.09)**	(0.66)
AECO *(US$/mmbtu)*	**5.00**	4.78
Average exchange rate	**1.3012**	1.4010
AECO price *(Cdn$/mmbtu daily average)*	**6.51**	6.70
Variance: Progress pool price vs spot	**0.71**	0.12
Progress average realized Alberta price *(Cdn$/mcf)*	**7.22**	6.82

British Columbia Natural Gas Prices

	2004	2003
NYMEX *(US$/mmbtu 12 month average – last 3 days)*	**6.09**	5.44
Less: Station #2 basis differential to Henry Hub *(US$/mmbtu)*	**(1.12)**	(0.76)
Station #2 *(US$/mmbtu)*	**4.97**	4.68
Average exchange rate	**1.3012**	1.4010
Station #2 price *(Cdn$/ mmbtu daily average)*	**6.46**	6.56
Variance: Progress pool price vs. spot	**0.51**	0.08
Progress average realized British Columbia price *(Cdn$/mcf)*	**6.97**	6.64

Risk Management

The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. The Risk Management Policy has the following objectives:

- To reduce risk exposure to budgeted annual cash flow projections resulting from uncertainty or changes in commodity prices, interest rates or foreign exchange
- To provide greater certainty and stability to monthly distributions.
- To limit the permissible structures to ensure hedging effectiveness.
- To limit hedging up to a maximum of 50 percent of budgeted production.
- To limit hedging activity to counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

In 2004, the Trust entered into a number of financial transactions for natural gas and crude oil as well as physical transactions for natural gas whereby it entered into monthly index swaps, bought put options and entered into collar transactions. Progress' commodity risk management positions are fully described in Note 10 in the consolidated financial statements attached. As at December 31, 2004 the Trust would have received $3.7 million on the termination of these contracts.

The Trust currently has natural gas financial contracts in place for the following production volumes:

Financial Price Risk Management	Contract Natural Gas Volumes *('000 GJ/d)*	% of Estimated Natural Gas Production Net of Royalties
First quarter of 2005	45.0	70
Second quarter of 2005	30.0	50
Third quarter 2005	30.0	50
Fourth quarter 2005	10.0	15

Sensitivities

	Estimated Effect on 2005 Cash Flow per Trust Unit
Change of $0.25 per mcf in the price of natural gas	$0.07
Change of US$5.00 per barrel in the price of WTI	$0.07
Change of 5,000 mcf/d in natural gas production	$0.10
Change of 500 bbls/d in crude oil production	$0.07
Change of $0.01 in the US$/Cdn$ exchange rate	$0.03
Change of 1% in prime interest rate	$0.02

These sensitivities reflect all commodity contracts as described in Note 10 of the consolidated financial statements. They apply to prices, production, interest and exchange rates within the context of current market rates. The sensitivities above will no longer apply above the ceiling or below the floor price limits set by existing commodity contracts.

Revenue

Petroleum and natural gas revenue increased 100 percent to $214.7 million in 2004 from $107.5 million in 2003 mainly due to higher production volumes as a result of the Cequel acquisition and successful drilling at the shallow foothills, northeast British Columbia core area, partially offset by the transfer of properties to ProEx. Production increased 81 percent from 7,459 boe per day in 2003 to 13,519 boe per day in 2004 while realized commodity prices increased 10 percent from $39.50 per boe in 2003 compared to $43.39 per boe in 2004. Petroleum and natural gas revenue in 2004 before hedging consisted of $161.2 million from natural gas sales, $43.3 million from crude oil sales and $13.5 million from the sale of natural gas liquids.

($ thousands)	**2004**	2003	% Change
Natural gas sales	**161,170**	70,314	129%
Crude oil sales	**43,344**	34,002	27%
Natural gas liquids sales	**13,526**	3,611	275%
Hedge settlements	**(1,658)**	(716)	
Amortization of hedge premiums	**(709)**	(883)	
Amortization of a commodity sales contract [1]	**762**	838	
Change in the fair value of financial instruments [2]	**(1,746)**	373	
Petroleum and natural gas revenue	**214,689**	107,539	100%

[1] *Amortization of physical natural gas sales contract acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002. Contract expires in 2008.*

[2] *Change in fair value of financial instrument of ineffective hedges or contracts that did not qualify for hedge accounting.*

Royalties

Royalty expense consists of royalties paid to provincial governments, freehold landowners and overriding royalty owners. Royalties increased 137 percent to $53.4 million in 2004 from $22.6 million in 2003 due to increased revenue primarily as a result of the Cequel acquisition and successful drilling in British Columbia. The Trust's average royalty rate in 2004 was 24.5 percent (before the impact of hedging charges) compared to 22.6 percent in 2003. The higher royalty rate in 2004 is attributable to the increase gas weighting of the Trust's production, as the Trust's effective royalty rate on natural gas (26.1 percent) is higher than crude oil (17.9 percent).

($ thousands)	**2004**	2003
Royalties		
Crown	**44,482**	17,990
Freehold and other	**8,940**	4,597
	53,422	22,587
Total *($/boe)*	**10.80**	8.30
Average royalty rate *(after impact of hedging charges – %)*	**24.9**	22.6
Average royalty rate *(before impact of hedging charges – %)*	**24.5**	22.5

Royalties by Product

The following table provides a break down of royalties by product. Rates are calculated before the impact of hedging activities and Alberta royalty tax credit:

($ thousands)	**2004**	2003
Natural gas royalties	**42,037**	16,675
$/boe	**11.08**	9.47
Average natural gas royalty rate *(%)*	**26.1**	25.9
Crude oil royalties	**7,773**	5,393
$/boe	**9.10**	6.32
Average crude oil royalty rate *(%)*	**17.9**	16.7
Natural gas liquids royalties	**3,612**	986
$/boe	**12.12**	9.03
Average natural gas liquids royalty rate *(%)*	**26.7**	27.3

Management anticipates, based on current commodity prices that the average royalty rate for 2005, before the impact of hedging, will be approximately 25 percent.

Operating Expenses

Operating expenses increased 90 percent to $29.1 million in 2004 compared to $15.3 million in 2003. The increase in operating expenses is mainly attributable to the Cequel acquisition. On a boe basis, operating expenses for 2004 increased four percent to $5.87 from $5.63 in 2003. The increase in 2004 is primarily the result of increased operating expense per boe on the Trust's crude oil properties acquired as part of the Cequel acquisition.

The Trust purchased eight previously leased gas compressors in the fourth quarter of 2004 for a total purchase price of $3.0 million. These purchases will reduce operating expenses by $1.0 million in 2005 as the result of eliminating compressor rental fees. Management anticipates operating expenses for 2005 to be between $5.25 and $5.50 per boe.

($ thousands)	**2004**	2003	% Change
Total operating expenses	**29,050**	15,328	
$/boe	**5.87**	5.63	4%
Natural gas properties operating expenses	**19,203**	8,786	
$/boe	**4.82**	4.82	0%
Crude oil properties operating expenses	**9,847**	6,542	
$/boe	**10.20**	7.26	40%

Transportation Expenses

Transportation expenses increased 50 percent to $11.4 million in 2004 compared to $7.6 million in 2003. On a boe basis, transportation expenses in 2004 decreased 18 percent to $2.31 compared to $2.81 in 2003. The decrease on a boe basis is mainly attributable to a decrease in the proportion of production from British Columbia. As a result of the Cequel acquisition the Trust's production in British Columbia went from representing 47 percent of total production in 2003 to 43 percent in 2004. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Operating Netbacks

Although many wells produce both crude oil and natural gas, a well is categorized as a natural gas well or an oil well based upon the proportion of natural gas or crude oil production. The following table summarizes the operating netbacks for natural gas and oil properties:

	2004	2003
Natural Gas Properties *($/mcf)*		
Sales price – before hedging	**7.10**	6.59
Hedging settlements	**0.10**	0.07
Amortization of hedge premiums	**(0.02)**	(0.07)
Amortization of commodity sales contract	**0.03**	0.08
Change in fair value of financial instruments	**(0.06)**	–
Royalties	**(1.81)**	(1.60)
Operating expenses	**(0.80)**	(0.80)
Transportation expenses	**(0.32)**	(0.54)
Operating netback – natural gas properties	**4.22**	3.73
Oil Properties *($/bbl)*		
Sales Price – before hedging	**48.10**	39.88
Hedging settlements	**(4.47)**	(1.68)
Amortization of hedge premiums	**(0.21)**	(0.12)
Change in fair value of financial instrument	**–**	0.41
Royalties	**(10.61)**	(6.23)
Operating expenses	**(10.20)**	(7.26)
Transportation expenses	**(1.88)**	(1.94)
Operating netback – oil properties	**20.73**	23.06

General and Administrative Expenses

General and administrative expenses net of overhead recoveries on operated properties, ("G&A") increased 55 percent to $5.6 million ($1.14 per boe) in 2004 compared to $3.6 million ($1.34 per boe) in 2003. The increase in G&A expense is due to the increase in full-time and contract staff required as a result of the increased size of the Trust's operations due to the Cequel acquisition.

($ thousands)	**2004**	2003
Gross G&A	**9,463**	6,359
Performance Unit Incentive Plan	**502**	–
Stock based compensation cost	–	246
Operator recoveries	**(2,833)**	(2,017)
Capitalized expenses	**(1,492)**	(943)
Net G&A	**5,640**	3,645
Net G&A *($/boe)*	**1.14**	1.34

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust provides personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one year prior written notice to the other party or some other date as mutually agreed. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expenses reimbursed by ProEx and netted against gross G&A expenses above for 2004 were $0.6 million.

The Progress Performance Unit Incentive Plan (the "Plan") is a long-term incentive program approved in conjunction with the Arrangement and finalized by the Board of Directors in December 2004. The Plan provides for employees, directors and contract employees ("service providers") to be granted trust units and accumulated distributions over a three year performance period. At the end of the performance period service providers will earn and be paid from 0.5 to 1.5 times their initial trust unit grant based on the performance of the Trust as it compares to its peers. Performance will be measured based on total trust unit return (change in trust unit price and accumulated distributions) of Progress compared to a peer group of 12 trusts. Payment may be in the form of cash or trust units, at the Trust's option. Management anticipates, at the end of the performance period, accumulated distributions will be paid in cash and trust units will be paid from treasury. As a result, accumulated distributions are accounted for as a reduction to cash flow and the amortization of the trust unit grants are accounted for as a non-cash charge.

The magnitude of operator recoveries is a function of activity levels and the degree to which operations are operated by the Trust. Progress operates 89 percent of its production and generally operates all of the drilling and construction activity. Operator recoveries for 2004 were $2.8 million compared to $2.0 million in 2003. This increase is primarily a result of a larger exploration and development capital program during the year.

The Trust capitalized approximately $1.5 million of G&A in 2004 and $0.9 million in 2003. The majority of these costs represent geological and geophysical salaries.

Management anticipates G&A expense to average approximately $1.25 per boe in 2005.

Interest and Financing Expenses

Interest and financing expenses in 2004 increased 65 percent to $3.4 million compared to $2.1 million in 2003. The increase is primarily due to higher average debt levels due to the assumption of Cequel's debt, net of $10.0 million of debt assumed by ProEx (refer to Plan of Arrangement).

($ thousands)	**2004**	2003
Financing charges	**3,431**	2,084
Cost *($/boe)*	**0.69**	0.77
Average total debt outstanding	**99,179**	51,883
Average interest rate *(%)*	**3.5**	4.0

Subsequent to year end the Trust issued $100 million principal amount of 6.75 percent convertible unsecured subordinated debentures (the "Debentures"). The Debentures pay interest semi-annually, have a maturity date of June 30, 2010 and are convertible, at the option of the holder, at any time into fully paid trust units of Progress at a conversion price of $15.00 per trust unit. The net proceeds of the financing were used to reduce outstanding bank indebtedness. Management anticipates as a result of this transaction the Trust's interest rate for 2005 will increase to approximately six percent.

Depletion, Depreciation and Accretion

Depletion and depreciation of property, plant and equipment and the accretion of the asset retirement obligations ("DD&A") increased 131 percent to $58.6 million in 2004 from $25.3 million in 2003. The increase is due to both higher production and a higher depletable base in 2004 as a result of the Cequel acquisition. On a boe basis DD&A has increased due to the acquisition of Cequel and the inclusion of these assets at their fair market value. DD&A per boe in 2004 was $11.84 compared to $9.30 in 2003.

($ thousands)	**2004**	2003
Depletion [1]	**57,129**	24,169
Depreciation	**376**	171
Accretion of asset retirement obligation [1]	**1,083**	972
Depletion, depreciation and accretion expense	**58,588**	25,312
DD&A *($/boe)*	**11.84**	9.30
DD&A *(%)*	**13.8**	12.7

[1] The above amounts have been restated for the change in accounting policy related to asset retirement obligations.

Income and Capital Taxes

Capital taxes were $1.5 million in 2004 and $0.8 million in 2003. This increase is primarily attributable to the Cequel acquisition. The provision for future income taxes in 2004 decreased to a recovery of $4.2 million from an expense of $8.9 million in 2003. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. It is expected the Trust will not incur any cash income taxes in the future and as such the future tax liability recorded on the balance sheet will recover through future net earnings.

Net Earnings and Cash Flow

Net earnings increased 147 percent to $52.6 million in 2004 compared to $21.2 million in 2003. The increase was primarily due to the Cequel acquisition and the reorganization into a trust which resulted in the Trust recording an income tax recovery during the third and fourth quarter of 2004. Basic net earnings in 2004 were $0.91 per trust unit compared to $0.68 per trust unit in 2003. Similarly, diluted net earnings in 2004 were $0.89 per trust unit compared to $0.63 per trust unit in 2003.

Cash flow increased 104 percent to $110.5 million in 2004 compared to $54.3 million in 2003 mainly due to higher natural gas production as a result of the Cequel acquisition. Diluted cash flow in 2004 was $1.87 per trust unit compared to $1.62 per trust unit in 2003.

Quarterly Financial Summary [1, 2]

($ thousands, except per unit amounts)

	Three Months Ended							
	Dec. 31 2004	Sept. 30 2004	Jun. 30 2004	Mar. 31 2004	Dec. 31 2003	Sept.30 2003	Jun. 30 2003	Mar. 31 2003
Petroleum and natural gas revenue	76,767	68,299	38,811	30,812	28,370	24,939	24,784	29,446
Cash flow	41,344	36,355	17,833	14,928	13,391	12,317	12,502	16,045
Per unit basic	0.50	0.45	0.52	0.44	0.41	0.39	0.40	0.52
Per unit diluted	0.50	0.45	0.49	0.41	0.39	0.37	0.37	0.48
Net earnings	22,717	19,149	4,464	6,247	4,293	3,647	6,835	6,470
Per unit basic	0.28	0.24	0.13	0.19	0.13	0.12	0.22	0.21
Per unit diluted	0.28	0.24	0.12	0.17	0.12	0.11	0.20	0.20

[1] *The above amounts have been restated for changes in accounting policies related to asset retirement obligations and transportation expense. Refer to Note 1 in the consolidated financial statements attached.*

[2] *Quarterly petroleum and natural gas revenue and cash flow remained relatively constant in 2003 and increased in the first two quarters of 2004 primarily due to increasing production due to successful drilling in British Columbia. Third and fourth quarter 2004 petroleum and natural gas revenue and cash flow increased primarily due to the Cequel acquisition and successful drilling at the shallow foothills, northeast British Columbia core area, partially offset by the transfer of assets to ProEx as part of the Arrangement.*

FOURTH QUARTER ANALYSIS

	Q4 2004	Q3 2004	Q4 2003
Operational Highlights			
Daily Production			
Natural gas *(mcf/d)*	**86,998**	81,783	33,237
Crude oil *(bbl/d)*	**2,475**	2,475	2,629
Natural gas liquids *(bbl/d)*	**1,394**	1,197	315
Total daily production *(boe/d)*	**18,368**	17,302	8,483
Average Benchmark Prices			
AECO (daily) natural gas *($/mcf)*	**6.43**	6.21	5.72
WTI crude oil *(US$/bbl)*	**48.28**	43.88	31.18
Edmonton par price *(Cdn$/bbl)*	**57.74**	56.15	39.58
Exchange rate *(US$/Cdn$)*	**0.8192**	0.7650	0.7600
Average Realized Prices			
Natural gas – before hedging *($/mcf)*	**7.32**	6.94	5.89
Natural gas – after hedging *($/mcf)*	**7.45**	6.99	6.04
Crude oil – before hedging *($/bbl)*	**55.69**	53.35	37.73
Crude oil – after hedging *($/bbl)*	**48.21**	47.31	36.35
Natural gas liquids *($/bbl)*	**48.24**	45.09	32.71
Financial Highlights *($ thousands, except per unit amounts)*			
Petroleum and natural gas revenue	**76,767**	68,299	28,370
Royalties	**(19,572)**	(16,750)	(6,053)
Operating expenses	**(9,383)**	(9,255)	(4,432)
Transportation expenses	**(3,309)**	(3,152)	(2,303)
General and administrative expenses	**(2,095)**	(1,938)	(1,403)
Cash flow from operations	**41,344**	36,355	13,391
Depletion, depreciation and accretion	**22,540**	20,645	7,329
Net earnings	**22,717**	19,149	4,293
Per unit basic	**0.28**	0.24	0.13
Per unit diluted	**0.28**	0.24	0.12
Balance Sheet			
Capital expenditures	**33,994**	12,112	18,858

Production

Production during the fourth quarter of 2004 increased by six percent to 18,368 boe per day compared to 17,302 boe per day in the third quarter of 2004, and increased 117 percent compared to the fourth quarter of 2003 at 8,483 boe per day. The production increase from the third quarter to the fourth quarter in 2004 was primarily the result of wells returning to production after scheduled plant maintenance at McMahon, Gold Creek and Thorsby during the third quarter. The production increase from the fourth quarter of 2004 compared to the fourth quarter of 2003 was primarily due

to the Cequel acquisition and successful drilling at the shallow foothills, northeast British Columbia core area, partially offset by the transfer of assets to ProEx as part of the Arrangement.

Revenue

Petroleum and natural gas revenue for the fourth quarter of 2004 increased 12 percent to $76.8 million compared to the third quarter of 2004 of $68.3 million and increased 171 percent over the $28.4 million recognized for the fourth quarter of 2003. The increase in petroleum and natural gas revenue in the fourth quarter of 2004 compared to the third quarter of 2004 was primarily the result of increased production. The increase from the fourth quarter of 2004 to the fourth quarter of 2003 is primarily the result of increased production and higher natural gas prices.

Royalties

Royalties for the fourth quarter of 2004 increased 17 percent to $19.6 million compared to the third quarter of 2004 of $16.8 million and increased 223 percent over the $6.1 million recognized for the fourth quarter of 2003. The average royalty rate (before the impact of hedging charges) remained relatively consistent with the fourth quarter of 2004 at approximately 25.3 percent compared to 24.2 percent in the third quarter of 2004. The higher royalty rate in the fourth quarter of 2004 compared to a royalty rate of 21.9 percent in the fourth quarter of 2003 is attributable to the increased gas weighting of the Trust's production, as the Trust's effective royalty rate on natural gas is higher than crude oil.

Operating Expenses

Operating expenses for the fourth quarter of 2004 increased one percent to $9.4 million over the third quarter of 2004 of $9.3 million and increased 112 percent over the fourth quarter of 2003 of $4.4 million. Operating expenses during the fourth quarter of 2004 averaged $5.55 per boe compared to $5.81 per boe during the third quarter of 2004 and $5.68 per boe during the fourth quarter of 2003. Higher operating expense per boe in the third quarter of 2004 was the result of scheduled plant maintenance at several facilities.

Transportation Expenses

Transportation expenses for the fourth quarter of 2004 increased five percent to $3.3 million over the third quarter of 2004 of $3.2 million and increased 44 percent over the fourth quarter of 2003 of $2.3 million. Transportation expenses during the fourth quarter of 2004 averaged $1.96 per boe compared to $1.98 per boe during the third quarter of 2004 and $2.95 per boe during the fourth quarter of 2003. As a result of the Cequel acquisition, the Trust's production in British Columbia went from representing 47 percent of total production in 2003 to 43 percent in 2004, resulting in reduced transportation expense per boe. In British Columbia, there is an infrastructure owned by Duke Energy that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

General and Administrative Expense

G&A for the fourth quarter of 2004 increased eight percent to $2.1 million compared to the third quarter of 2004 of $1.9 million and increased 49 percent over the fourth quarter of 2003 of $1.4 million. G&A expenses averaged $1.24 per boe during the fourth quarter of 2004 compared

to $1.22 in the third quarter of 2004 and $1.80 during the fourth quarter of 2003. In the fourth quarter of 2003 G&A expenses include annual provisions for year end audit, reserve report and employee bonuses.

G&A expenses are forecasted to be approximately $1.25 per boe for 2005.

Income and Capital Taxes

Capital taxes for the fourth quarter decreased nine percent to $0.5 million compared to the third quarter of 2004 of $0.6 million and increased 130 percent over the fourth quarter of 2003 of $0.2 million. This increase from 2003 is primarily attributable to the Cequel acquisition. The provision for future income taxes in the fourth quarter of 2004 decreased to a recovery of $4.5 million from an expense of $1.8 million in the fourth quarter of 2003. The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. It is expected the Trust will not incur any cash income taxes in the future and as such the future tax liability recorded on the balance sheet will recover through future net earnings.

Depletion, Depreciation and Accretion

DD&A expense for the fourth quarter of 2004 was $22.5 million compared to $20.6 million for the third quarter of 2004 and $7.3 million for the fourth quarter of 2003. The increase in the fourth quarter is due to both higher production and a higher depletable base in 2004 due to the Cequel acquisition. This resulted in depletion and depreciation of $13.34 per boe for the fourth quarter of 2004 compared to $12.97 per boe for the third quarter of 2004 and $9.39 for the fourth quarter of 2003. On a boe basis, DD&A in 2004 increased due to the acquisition of Cequel and the inclusion of these assets at their fair market value.

Net Earnings and Cash flow

Net earnings for the fourth quarter of 2004 were $22.7 million compared to $19.1 million for the third quarter of 2004 and $4.3 million for the fourth quarter of 2003. The increase in net earnings over both the third quarter of 2004 and fourth quarter of 2003 is mainly due to higher revenue from increased production.

Capital Expenditures

During the fourth quarter the Trust incurred $28.3 million on exploration and development capital including $0.8 million in land acquisition and retention, $0.4 million in geological and geophysical, $18.5 million in drilling and completions and $8.6 million in facility construction. During the fourth quarter the Trust drilled 21 gross wells (9.7 net) with 10 gross wells drilled in the shallow foothills of northeast British Columbia, three gross wells in the Fort St John plains, British Columbia core area and eight gross wells drilled in Alberta. Included in facility charges in the fourth quarter is the purchase of nine gas compressors for a total purchase price of $4.0 million.

Net capital investment during the fourth quarter was $34.0 million compared to $12.1 million in the third quarter of 2004 and $18.9 million in the fourth quarter of 2003. Net property acquisitions during the fourth quarter were $5.3 million, primarily the result of undeveloped land purchased from a third party in the shallow foothills of northeast British Columbia.

DISTRIBUTABLE CASH AND DISTRIBUTIONS

Management monitors the Trust's distribution payout policy with respect to forecasted net cash flow, debt levels and capital expenditures. Progress expects to distribute approximately 70 percent of its annual cash flow to unitholders and retain the remaining cash flow for capital expenditures and debt repayment. Exchangeable shares are convertible into trust units of the Trust based on the exchange ratio, which is adjusted monthly to reflect that distributions are not paid on the exchangeable shares and cash flow related to the exchangeable shares is retained by the Trust for additional capital expenditures or debt repayment. The key drivers of Progress' cash flow, as is generally the case with other energy trusts, are commodity prices and production. Since the Trust's production is heavily weighted to natural gas (77 percent in 2004), natural gas prices have a significant effect on its cash flow.

Distributable cash is not a measure under GAAP and there is no standard measure of distributable cash. Distributable cash, as presented, may not be comparable to similar measures presented by other trusts. Progress' initial cash distribution declared was $0.14 per trust unit for the month of July. The Trust maintained this cash distribution per unit throughout the year.

($ thousands, except per unit amounts)	Six Months Ended December 31, 2004
Cash flow from operations before changes in non-cash working capital	**77,712**
Cash withheld to fund capital expenditures	**22,007**
Cash distributions declared	**55,705**
Accumulated cash distributions, beginning of period	–
Accumulated cash distributions, end of period	**55,705**
Cash distributions per unit [1]	**0.84**
Accumulated cash distributions per unit, beginning of period	–
Accumulated cash distributions per unit, end of period	**0.84**

[1] *Cash distributions per trust unit reflect the sum of the per trust unit amounts paid and declared to unitholders.*

Capital Expenditures

The Trust invested approximately $106.4 million in net capital expenditures in 2004 compared to $84.3 million in 2003.

($ thousands)	**2004**	2003
Land acquisitions and retention	**9,883**	11,999
Geological and geophysical	**7,225**	6,522
Drilling and completions	**57,177**	45,674
Equipping and facilities	**32,679**	23,917
Net property acquisitions (dispositions)	**(1,986)**	(4,160)
Corporate assets	**1,444**	342
Total net capital expenditures	**106,422**	84,294

Progress drilled 64 gross wells (41.9 net) with an 89 percent success rate in 2004. Included in this drilling activity are 26 gross wells (18.2 net) drilled in the shallow foothills of northeast British Columbia. Additionally, eight wells (1.6 net) were drilled in the Gundy field. The success of the

drilling program in the shallow foothills of northeast British Columbia continues to support the long-term development potential of this tight, multi-zone gas region. In the Trust's largest producing region, Gold Creek in northwest Alberta, the Trust drilled nine gross wells (5.0 net) during the year.

The Trust expects to drill 75 to 80 gross wells, or 40 to 45 net, in 2005 with approximately 45 gross wells (24 net) focused in the foothills and plains regions of northeast British Columbia and approximately 30 gross wells (17 net) planned in the Gold Creek area of northwest Alberta on a capital program totaling approximately $70.0 to $75.0 million. The Trust's capital investment program is expected to be split approximately 65 percent to drilling and completions, 20 percent to facilities with the remaining 15 percent allocated to land and seismic expenditures. The Trust does not set a budget for property acquisitions.

Undeveloped Land

Undeveloped land at year end increased 59 percent to 569,479 acres compared to 358,602 acres in 2003 due to the acquisition of Cequel and an active land acquisition program. The Trust purchased approximately 94,000 net acres at Crown land sales during 2004 and acquired 14,000 net freehold acres in Progress' core areas. Two fourth quarter acquisitions in the shallow foothills of northeast British Columbia added an additional 25,000 net acres of which 8,000 net acres have a commitment by ProEx to shoot seismic and drill at their cost to evaluate prospectivity. Progress continues to maintain a high working interest in its undeveloped land. Progress' average working interest in its undeveloped land at year end was 70 percent.

	2004		2003	
(acres)	**Gross**	**Net**	Gross	Net
Alberta	**412,238**	**333,245**	174,184	139,227
British Columbia	**322,316**	**164,276**	196,659	137,592
Saskatchewan	**77,141**	**71,958**	86,476	81,783
Total undeveloped land	**811,695**	**569,479**	457,319	358,602

At year end the Trust had an option to earn an interest in 18,000 gross acres of undeveloped land in British Columbia. The Trust, at its option, can earn an interest in part or all of these lands by drilling up to four wells.

Over the next 12 months 125,000 net acres or 22 percent of Progress' undeveloped land will be subject to expiry. The Trust has an active farmout strategy in place with 112,000 net acres of undeveloped land committed under farmout agreements at standard industry terms.

Goodwill

The Trust recorded goodwill of $405.7 million in 2004 as a result of the acquisition of Cequel. In 2002 Progress attributed $9.0 million of value to goodwill in the acquisition of Campion Resources Ltd., resulting in a total of $414.7 million of goodwill recorded on Progress' balance sheet at year end. In accordance with Canadian GAAP goodwill is not amortized but is subject to an impairment test. Progress conducts a goodwill impairment test on an annual basis at its fiscal year end. Goodwill may be tested for impairment between annual tests in certain situations. There was no impairment of goodwill as a result of the tests conducted at December 31, 2004 and 2003.

Liquidity and Capital Resources

($ thousands)	2004	2003
Working capital deficiency	**37,821**	10,360
Bank debt	**133,722**	45,073
Total debt	**171,543**	55,433

At December 31, 2004 the Trust had $133.7 million outstanding on its credit facility and a working capital deficiency of $37.8 million, resulting in $171.5 million of total debt. In conjunction with the Arrangement, the Trust entered into new credit facilities with a syndicate of banks and currently has a $200 million extendible revolving term credit facility and a $15 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 31, 2005, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. The credit facilities are secured by a $500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress in respect of the Trust's obligations. The $215 million borrowing base is subject to semi-annual review by the banks.

Bank debt increased from $45.1 million as at December 31, 2003 to $133.7 million as at December 31, 2004. This increase is primarily the result of the assumption of Cequel's debt, net of $10.0 million of debt assumed by ProEx and capital expenditures. Working capital deficiency increased from $10.4 million as at December 31, 2003 to $37.8 million as at December 31, 2004 due to increased accounts payable and accrued liabilities as a result of increased capital spending in the fourth quarter of 2004.

Subsequent to year end, on February 2, 2005, the Trust issued $100 million principal amount of 6.75 percent convertible unsecured subordinated debentures. The Debentures pay interest semi-annually, have a maturity date of June 30, 2010 and are convertible, at the option of the holder, at any time into fully paid trust units of Progress at a conversion price of $15.00 per trust unit. The net proceeds of the financing were initially used to reduce outstanding bank indebtedness. The Debentures are listed for trading on the Toronto Stock Exchange under the symbol PGX.DB.

The Trust's investing activities for 2004 primarily consists of expenditures on its capital program and distributions to unitholders. Management anticipates that the Trust will continue to have adequate liquidity to fund future working capital and forecasted capital expenditures during 2005 through a combination of cash flow and debt. Cash flow used to finance these commitments may reduce the amount of cash distributions paid to unitholders.

Commitments

The Trust contracts for firm transportation on the TransCanada PipeLines Limited and ATCO Ltd. systems in Alberta and the Duke Energy Corp. system in British Columbia. Service is contracted on a term basis with revolving renewals.

The Trust must pay Crown royalty, surface rentals, mineral taxes and abandonment and reclamation costs with respect to its ongoing ownership of hydrocarbon production rights. The amounts paid with respect to these burdens will depend on the future ownership, production, prices and legislative environment at the time.

Reserves producing approximately five percent of Progress' current production are dedicated to certain aggregator sales arrangements. Under these arrangements, Progress' receives a price based on the average netback price of the pool, net of transportation expenses incurred by the aggregator for the life of the reserves.

Progress has the following minimum annual commitments:

		Minimum Annual Commitment		
($ thousands)	Total	2005	2006	2007 – 2009
Bank debt [1]	133,722	–	133,722	
Pipeline commitments	21,612	11,105	8,843	1,664
Total commitments	155,334	11,105	142,565	1,664

[1] *Based on the existing terms of the revolving credit facilities which are subject to renewal on or before May 31, 2005. If not extended, the facilities would be available on a non-revolving basis for a one-year term at which time the facilities would be due and payable.*

In addition, the Trust has commitments related to its commodity risk management program (refer to Note 10 of the consolidated financial statements of Progress).

TAX INFORMATION

This information is intended to provide general guidance regarding taxation matters to any particular holder or potential holder of Progress trust units and exchangeable shares. It is not meant to be an exhaustive discussion of all possible income tax considerations nor is it intended to be legal or tax advice to any particular holder or potential holder of Progress trust units. Holders or potential holders of trust units or shares should consult their own tax advisor as to the particular income tax consequences of holding the trusts units.

Exchangeable Shareholders The exchangeable shares are listed on the TSX under the symbol "PGE" and are convertible into trust units, at the option of the shareholder, based on the then current exchange ratio. Exchangeable shareholders are not eligible to receive monthly cash distributions, however the exchange ratio increases on a monthly basis by an amount equal to the current month's trust unit distribution multiplied by the then current exchange ratio and divided by the five day weighted average trading price of the trust units at the end of each month. The gain realized as a result of the monthly increase in the exchange ratio is, in most circumstances, taxed as a capital gain rather than income and is therefore subject to a lower effective tax rate. Tax on the exchangeable share is deferred until the exchangeable share is sold or converted into trust units.

Canadian Individual Trust Unitholders The Trust currently qualifies as a mutual fund trust under the Income Tax Act (Canada) and, accordingly, trust units of the Trust are qualified investments for RRSP's, RRIF's, RESP's and DPSP's. Each year, the Trust is required to file an income tax return and any taxable income in the Trust is allocated to unitholders. Unitholders are generally required

to include in computing income, their pro-rata share of any taxable income earned by the Trust in that year. An investor's adjusted cost base ("ACB") in a trust unit equals the purchase price of the trust units less any non-taxable cash distributions received from the date of acquisition. To the extent a unitholder's ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholder's ACB will be brought to $nil.

Progress declared cash distributions of $0.84 per trust unit in respect of 2004. For Canadian tax purposes, 10 percent of these distributions or $0.084 per trust unit was a tax deferred return of capital, 90 percent or $0.756 per trust unit was taxable to unitholders as other income.

Management estimates that approximately 90 percent of the distributions to Canadian unitholders in 2005 will be taxable and the remaining 10 percent will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions which are dependant upon production, commodity prices and cash flow experienced throughout the year.

United States Resident Unitholders United States ("US") resident unitholders who receive cash distributions are generally subject to a 15 percent Canadian withholding tax, applied to 100 percent of the cash distributions to US unitholders in 2005 as computed under Canadian tax law. US tax payers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid. The foreign tax credit limitations are very complex and US taxpayers should consult with their tax advisors regarding its application.

Progress elected to be treated as a corporation for US tax purposes. The taxable portion of the cash distribution for US tax purposes is determined by Progress in relation to its current and accumulated earnings and profits using US income tax principles. The taxable portion determined is considered to be a dividend for US tax purposes. For most US taxpayers this should be a "Qualified Dividend" eligible for the reduced tax rate.

The non-taxable portion of the cash distribution is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

Progress paid US$0.56 per trust unit in respect of 2004. For US tax purposes, 14.2 percent of these distributions or US$0.08 per trust unit was a tax deferred return of capital, approximately 85.8 percent or US$0.48 per trust unit was taxable dividend.

Management estimates that approximately 90 percent of cash distributions may be taxable dividend and 10 percent may be a tax deferred return of capital for tax purposes for 2005. Actual taxable amounts may vary depending on actual distributions which are dependant upon production, commodity prices and cash flow experienced throughout the year.

CRITICAL ACCOUNTING ESTIMATES

The financial statements have been prepared in accordance with Canadian GAAP. A summary of significant accounting policies are presented in Note 1 to the consolidated financial statements. Certain accounting policies are critical to understanding the financial condition and results of operations of Progress.

Depletion and Depreciation Expense

The Trust uses the full cost method of accounting for exploration and development activities whereby all costs associated with these activities are capitalized, whether successful or not. The aggregate of capitalized costs, net of certain costs related to unproved properties, and estimated future development costs is amortized using the unit-of-production method based on estimated proved reserves (refer to Risk Factors and Risk Management, Reserve Estimates). Changes in estimated proved reserves or future development costs have a direct impact on depletion and depreciation expense.

Certain costs related to unproved properties and major development projects may be excluded from costs subject to depletion until proved reserves have been determined or their value is impaired. These properties are reviewed quarterly to determine if proved reserves should be assigned, at which point they would be included in the depletion calculation, or for impairment, for which any write-down would be charged to depletion and depreciation expense.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligations

The asset retirement obligations is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonments and reclamations discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings and for revisions to the estimated future cash flows. By their nature, these estimates are subject to measurement uncertainty and the impact on the consolidated financial statements could be material.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

CHANGE IN ACCOUNTING POLICIES

Full Cost Accounting Guideline

Effective January 1, 2004, the Trust adopted the new Canadian accounting guideline for oil and gas accounting using the full cost method. In accordance with the new guideline, the Trust evaluates its oil and gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate.

Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the new Canadian accounting standard for asset retirement obligations. The year ended December 31, 2003 consolidated financial statements have been restated to reflect this change resulting in a reduction of $0.2 million to net earnings.

Transportation Expenses

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation expenses have been reclassified as an expense in the consolidated statements of earnings and accumulated earnings for year ended December 31, 2004 and 2003. Previously, as was industry practice, transportation expenses were netted off revenue.

Hedging Relationships

Effective January 1, 2004, the Trust adopted the new Canadian guidelines for hedging relationships. The adoption of this guidelines had no impact on the results of operations or financial position of the Trust.

Exchangeable Shares

On January 19, 2005, a new accounting abstract, "Exchangeable Securities Issued by Subsidiaries of Income Trusts", was issued effective for financial statements issued after the date of issue of this abstract. The abstract specifies that exchangeable shares are presented as equity only if certain circumstances exist, otherwise they are classified as non-controlling interest. The adoption of this abstract had no impact on the Trust's financial position or results of operations for the year ended December 31, 2004.

Per Unit Information

Per unit information is calculated on the basis of the weighted average number of trust units and issuable exchangeable shares outstanding during the fiscal year. Diluted per unit information reflects the potential dilution that could occur if securities or other contracts to issue units were exercised or converted to units. Diluted per unit information is calculated using the treasury stock method that assumes any proceeds received by the Trust upon the exercise of in-the-money unit options plus the unamortized unit compensation cost would be used to buy back trust units at the average market price for the period.

RISK FACTORS AND RISK MANAGEMENT

Investors that purchase trust units are participating in the net cash flow from a portfolio of natural gas and crude oil producing properties. As such, the cash flow paid to investors and the value of Progress' units is subject to numerous risk factors. Some of the risks are common to all businesses while many are associated with the oil and gas industry. The following information is only a summary of certain risk factors which could affect the Trust's future results:

Volatility of Commodity Prices

The Trust's results of operations and financial condition are dependent on prices received for the production of natural gas and crude oil. With the Trust's production heavily weighted to natural gas, changes to natural gas pricing have the most material effect on its cash flow. Prices for natural gas and crude oil have fluctuated significantly during recent years and are determined by supply and demand factors, including weather and general economic conditions as well as conditions in other oil producing regions, which are beyond the control of the Trust. Prices received from production in Canada also reflect changes in Canadian/US currency exchange rate. Any decline in the prices for natural gas and crude oil could have a material adverse effect on the Trust's operations, financial condition and the level of capital expenditures provided for the development of its natural gas and crude oil reserves.

Progress uses financial derivative instruments in an effort to limit a portion of the potential adverse effects resulting from volatility in natural gas and oil commodity prices, while retaining exposure to upside price movements. The Trust's hedging activities are conducted pursuant to the Trust's Risk Management Policy approved by the Board of Directors. To the extent commodity price exposure is hedged, the benefits that would otherwise be experienced if commodity prices were to increase would be foregone.

Operational Matters

The ownership and operation of oil and natural gas wells, pipelines and facilities involves a number of operating and natural hazards which may result in blowouts, environmental damage and other unexpected or dangerous conditions resulting in damage to the Trust's natural gas and oil properties and assets as well as possible liability to third parties. The Trust may become liable for damages arising from such events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce the cash flow of Progress.

Progress employs prudent risk management practices and maintains suitable liability insurance, where available. Business interruption insurance is also purchased for selected facilities, to the extent that such insurance is reasonably available.

Reserve Estimates

Estimates of economically recoverable natural gas and crude oil reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating expenses. All of these estimates may vary from actual results. Estimates of the recoverable natural gas and crude oil reserves attributable to any particular

group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Trust's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material.

Each year, a firm of independent engineers evaluates a significant portion of proved and probable reserves. At December 31, 2004, 100 percent of the reserves were evaluated.

Exploration and Development Risks

Oil and gas exploration and development requires manpower and capital to generate, develop and test exploration concepts. The eventual testing of a concept will not necessarily result in the discovery of economical reserves.

Progress attempts to minimize the risk of developing existing and new reserves by ensuring that: (a) the majority of prospects have multi-zone potential; (b) activity is focused in core regions were expertise and experience is greatest; (c) number of wells drilled is large enough to increase the probability of statistical success rates; (d) geophysical techniques are utilized where appropriate; (e) by focusing its activities in core areas and major play types allowing it to leverage off its experience and knowledge in these areas further aiding efficiencies; and (f) farm-outs are entered into to minimize risk on plays it considers higher risk.

Access to Capital Markets

The Trust distributes the majority of its cash flow to unitholders. Access to equity and debt markets is required for the Trust to finance acquisition and development activity to maintain and grow value to unitholders.

Progress' trust units are listed on the TSX and the Trust maintains an active investor relations program designed to facilitate access to the equity capital markets. Progress also maintains a prudent capital structure by retaining a portion of its net cash flow for debt repayment when appropriate, managing capital expenditures within rate of return risk parameters and by utilizing equity markets.

Regulatory Risk

There can be no assurance that government royalties, income tax laws, environmental laws and regulatory requirements relating to the oil and gas industry, such as the status of mutual fund trusts, will not be changed in a manner which adversely affects the Trust or its unitholders.

Although the Trust has no control over these regulatory risks, Progress continuously monitors changes in these areas to assess the impact of such changes on the Trust's financial and operating results.

Environment and Safety Risks

The Canadian oil and natural gas industry is subject to environmental and safety regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of the Trust or its properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on the Trust.

The Board of Directors has reviewed and approved policies and procedures covering environmental risks, emergency response and employee safety. These policies and procedures are designed to protect and maintain

the environment with respect to all corporate operations on behalf of unitholders, employees and the public at large. The Trust mitigates environmental and safety risks by maintaining its facilities, complying with all provincial and federal environmental and safety regulations and maintaining adequate insurance.

Credit Risks

The Trust assumes customer credit risk associated with natural gas and crude oil sales, financial hedging transactions and joint venture participants.

Management has established controls designed to mitigate the risk of default or nonpayment with respect to natural gas and crude oil sales, financial hedging transactions and joint venture participants.

OUTLOOK AND 2005 FORECAST

Progress will continue to pursue a disciplined approach to long-term sustainability on a per unit basis. Our technical approach and cost control will be primary contributors to sustained value creation for unitholders. Internally generated opportunities will be drilled at a more modest pace than when we were an aggressive growth company. Our inventory of drilling locations currently supports approximately two to three years of activity for Progress, while our nearly 600,000 net acres of undeveloped land provides the opportunity for our technical team to create incremental value.

In creating our new Trust, we ensured that we would have access to strong technical and financial people by having all employees invest in Progress. This creates strong alignment with our unitholders and ensures that we have the professional staff to execute our business plan. Employees, management and directors hold a 13 percent direct ownership interest in our Trust.

The following table summarizes the Trust's 2005 forecast provided throughout the MD&A. Progress does not forecast commodity prices and as a result, the Trust does not forecast cash distributions to unitholders.

2005 Forecast	Target
Production	18,500 to 19,500 boe/d
Royalty rate before hedging charges	25 percent
Operating expenses	$5.25 to $5.50 per boe
G&A expenses	$1.25 per boe
Average interest rate	6 percent
Capital expenditures	$70 to 75 million
Drilling activity	75 to 80 gross or 40 to 45 net wells
Cash flow pay-out ratio	70 percent

ADDITIONAL INFORMATION

Additional information regarding the Trust and its business and operations, including the annual information form ("AIF") is available on the Trust's company profiles at www.sedar.com. Copies of the AIF can also be obtained by contacting the Trust at Progress Energy Trust 1400, 440 – 2nd Avenue S.W., Calgary, Alberta, Canada T2P 5E9 or by e-mail at ir@progressenergy.com. This information is also accessible on the Trust's web site at www.progressenergy.com

REPORT OF MANAGEMENT

Progress Energy Trust

The accompanying consolidated financial statements of Progress Energy Trust and all the information in this annual report are the responsibility of management and have been approved by the Board of Directors.

The financial statements have been prepared by management in accordance with generally accepted accounting principles. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise since they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Progress Energy Trust maintains appropriate systems of internal accounting and administrative controls of high quality. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Trust's assets are properly accounted for and adequately safeguarded.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and is ultimately responsible for reviewing and approving the financial statements. The Board carries out this responsibility principally through its Audit Committee.

The Audit Committee of the Board of Directors, composed entirely of independent directors, meets regularly with management, as well as the external auditors, to discuss auditing (external and joint venture), internal controls, accounting policy and financial reporting matters. The committee reviews the consolidated financial statements and Management's Discussion and Analysis and recommends their approval to the Board of Directors. The Committee also considers, for review by the board and approval by the unitholders, the engagement or re-appointment of the external auditors.

The consolidated financial statements have been audited by KPMG LLP, the external auditors, in accordance with generally accepted auditing standards on behalf of the unitholders. KPMG LLP has full and free access to the Audit Committee.

Art MacNichol

Michael R. Culbert
President
Progress Energy Ltd.

Art A. MacNichol
Vice President Finance and CFO
Progress Energy Ltd.

February 22, 2005

AUDITORS' REPORT

Progress Energy Trust

To the Unitholders of Progress Energy Trust

We have audited the consolidated balance sheets of Progress Energy Trust as at December 31, 2004 and 2003 and the consolidated statements of earnings and accumulated earnings and cash flows for the years ended December 31, 2004 and 2003. These consolidated financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatements. An audit includes examining on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years ended December 31, 2004 and 2003 in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Calgary, Canada
February 22, 2005

KPMG LLP
Chartered Accountants

CONSOLIDATED BALANCE SHEETS

Progress Energy Trust

As at December 31 ($ thousands)	**2004**	2003 *(Restated Notes 1 and 6)*
ASSETS		
Current		
Cash and short-term investments	**–**	–
Accounts receivable	**30,863**	15,203
Prepaid expenses and deposits	**4,370**	2,790
	35,233	17,993
Property, plant and equipment *(Note 4)*	**633,615**	225,119
Goodwill *(Note 2)*	**414,655**	9,000
	1,083,503	252,112
LIABILITIES		
Current		
Accounts payable and accrued liabilities	**56,979**	28,353
Cash distributions payable	**9,366**	–
Current income taxes payable	**6,709**	–
	73,054	28,353
Bank debt *(Note 5)*	**133,722**	45,073
Commodity sales contract *(Note 10)*	**2,094**	2,856
Asset retirement obligations *(Notes 1 and 6)*	**16,065**	11,778
Future income taxes *(Note 8)*	**109,116**	32,274
	334,051	120,334
UNITHOLDERS' EQUITY		
Unitholders' capital *(Note 7)*	**614,579**	96,752
Exchangeable shares *(Note 7)*	**133,226**	–
Contributed surplus *(Note 7)*	**171**	246
Accumulated earnings	**57,181**	34,780
Accumulated cash distributions	**(55,705)**	–
	749,452	131,778
Subsequent event *(Note 11)*		
	1,083,503	252,112

See accompanying notes to the consolidated financial statements

Approved on behalf of the Board

David D. Johnson
Director

Donald F. Archibald
Director

CONSOLIDATED STATEMENTS OF EARNINGS AND ACCUMULATED EARNINGS

Progress Energy Trust

Year ended December 31 ($ thousands, except per unit amounts)	**2004**	2003
		(Restated Notes 1 and 6)
REVENUE		
Petroleum and natural gas	**214,689**	107,539
Royalties	**(53,422)**	(22,587)
	161,267	84,952
EXPENSES		
Operating	**29,050**	15,328
Transportation *(Note 1)*	**11,433**	7,646
General and administrative	**5,640**	3,645
Interest and financing	**3,431**	2,084
Depletion, depreciation and accretion	**58,588**	25,312
Plan of arrangement *(Note 3)*	**3,314**	–
	111,456	54,015
Earnings before taxes	**49,811**	30,937
TAXES *(Note 8)*		
Capital taxes	**1,454**	804
Future income taxes	**(4,220)**	8,888
	(2,766)	9,692
NET EARNINGS	**52,577**	21,245
Accumulated earnings, beginning of year	**36,290**	14,800
Retroactive application of change in accounting policy *(Notes 1 and 6)*	**(1,510)**	(1,265)
Accumulated earnings, beginning of year, as restated	**34,780**	13,535
Plan of arrangement *(Note 3)*	**(30,176)**	–
Accumulated earnings, end of year	**57,181**	34,780
NET EARNINGS PER UNIT *(Note 7)*		
Basic	**$ 0.91**	$ 0.68
Diluted	**$ 0.89**	$ 0.63

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Progress Energy Trust

Year ended December 31 ($ thousands)	**2004**	2003 *(Restated Notes 1 and 6)*
OPERATING ACTIVITIES		
Net earnings	**52,577**	21,245
Depletion, depreciation and accretion	**58,588**	25,312
Amortization of commodity sales contract	**(762)**	(838)
Unit based compensation expense	**2,889**	246
Asset retirement expenditures	**(358)**	(225)
Change in fair value of financial instruments *(Note 10)*	**1,746**	(373)
Future income taxes	**(4,220)**	8,888
Cash flow from operations	**110,460**	54,255
Changes in non-cash working capital *(Note 9)*	**21,971**	(1,318)
	132,431	52,937
FINANCING ACTIVITIES		
Increase in bank debt	**44,176**	1,687
Cash distributions	**(46,339)**	–
Issue of units *(Note 7)*	**8,403**	22,729
Plan of arrangement *(Note 3)*	**(21,943)**	–
Unit issue costs *(Note 7)*	**(2,001)**	(1,177)
Changes in non-cash working capital *(Note 9)*	**(268)**	268
	(17,972)	23,507
INVESTING ACTIVITIES		
Corporate acquisition *(Note 2)*	**(1,597)**	–
Capital expenditures	**(106,422)**	(84,294)
Change in non-cash working capital *(Note 9)*	**(6,440)**	4,904
	(114,459)	(79,390)
Change in cash and short-term investments	**–**	(2,946)
Cash and short-term investments, beginning of year	**–**	2,946
Cash and short-term investments, end of year	**–**	–

See accompanying notes to the consolidated financial statements

Progress Energy Trust ("Progress" or the "Trust") is an open-ended, unincorporated investment trust governed by the laws of the province of Alberta. The Trust was established as part of a Plan of Arrangement (the "Arrangement") that became effective on July 2, 2004.

The Arrangement gave effect to the transaction contemplated by the agreement entered into on May 28, 2004 by Progress Energy Ltd. and Cequel Energy Inc. ("Cequel"). The reorganization resulted in the shareholders of Progress Energy Ltd. and Cequel receiving trust units or exchangeable shares in the Trust, a new energy trust that owns approximately 90 percent of the combined assets of Progress Energy Ltd. and Cequel. In addition, the shareholders of Progress Energy Ltd. and Cequel received shares in two separate, publicly-listed, exploration-focused companies, ProEx Energy Ltd. ("ProEx") and Cyries Energy Inc. ("Cyries"). The remaining properties were transferred to ProEx and Cyries, respectively, consisting of certain prospective natural gas weighted assets and undeveloped land.

Pursuant to the Arrangement, shareholders of both Progress Energy Ltd. and Cequel received shares of both ProEx and Cyries and at their election, either units of the Trust or exchangeable shares which may be exchanged into units of the Trust. The Arrangement resulted in Progress Energy Ltd. shareholders receiving one trust unit or exchangeable share of the Trust and 0.2 of a share in each of ProEx and Cyries. Cequel shareholders received 0.695 trust units or exchangeable shares of the Trust and 0.139 of a share in each of ProEx and Cyries.

As part of the Arrangement, the Trust put in place new credit facilities totaling $215 million to replace existing debt (refer to note 5, Bank Debt).

Upon completion of the Arrangement, 65.4 million trust units and 16.0 million exchangeable shares were outstanding.

The conversion of Progress Energy Ltd. to a Trust has been accounted for as a continuity of interest. Accordingly, the consolidated financial statements for 2004 reflect the financial position, results of operations and cash flows as if the Trust had always carried on the business formerly carried on by Progress Energy Ltd. The year ended December 31, 2004 reflects the results of operations and cash flows of Progress Energy Ltd. and its subsidiaries for the period January 1 to July 1, 2004 and the results of operations and cash flows of the Trust and its subsidiary for the period July 2 to December 31, 2004. The comparative figures are the results of Progress Energy Ltd. and its subsidiaries. Due to the conversion into an energy trust, certain information included in the financial statements for prior periods may not be directly comparable.

The term "units" has been used to identify Trust units and exchangeable shares of the Trust issued on or after July 2, 2004 as well as the common shares of the corporation outstanding prior to the conversion on July 2, 2004.

Relationship with ProEx Energy Ltd.

In conjunction with the Arrangement, the Trust entered into a Technical Services Agreement with ProEx where the Trust shares personnel and certain administrative and technical services in connection with the management, development, exploitation and operation of the assets of ProEx. The Technical Services Agreement has no set termination date and will continue until terminated by either party with one

year prior written notice to the other party or some other date as mutually agreed. As contemplated in the Arrangement, ProEx has granted performance shares to the employees of Progress as service providers. The Trust provides these services to ProEx on an expense reimbursement basis, based on ProEx's monthly capital activity and production levels relative to the combined capital activity and production levels of both the Trust and ProEx. Total expense reimbursed by ProEx for the year ended December 31, 2004 was $0.6 million.

As a result of the Arrangement the Trust and ProEx have joint interest in certain properties and undeveloped land. These joint interest properties are governed by standard industry agreements and in addition the Trust has entered into a Protocol Arrangement with ProEx that specifies how each company will govern the management of the joint lands in specifically identified areas of interest. The Protocol Arrangement identifies methods and processes to be followed on both existing and new lands, joint facilities, marketing, seismic and surface rights. To ensure good governance practices, both the Trust and ProEx have each created independent committees of their Board of Directors to monitor compliance with the Technical Services Agreement and the Protocol Arrangement.

As at December 31, 2004, accounts payable included $4.1 million payable to ProEx which includes standard joint venture amounts including revenue. These amounts were paid subsequent to December 31, 2004. During the three months ended September 30, 2004, the Trust sold ProEx $3.1 million of assets it purchased during the three months ended June 30, 2004, in contemplation of the formation of ProEx. The assets primarily consisted of undeveloped land.

1. SIGNIFICANT ACCOUNTING POLICIES

Nature of Business and Basis of Presentation

The Trust is involved in the exploration, development and production of petroleum and natural gas in British Columbia, Alberta and Saskatchewan. The consolidated financial statements are stated in Canadian dollars and have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

Principles of Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiary.

Joint Operations

Substantially all of the exploration, development and production activities are conducted jointly with others and accordingly, the Trust only reflects its proportionate interest in such activities.

Measurement Uncertainty

The amounts recorded for depletion and depreciation of petroleum and natural gas property, plant and equipment and the asset retirement obligations and related accretion are based on estimates. The

cost recovery ceiling test is based on estimates of proved reserves, production rates, petroleum and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be material.

Cash and Short-Term Investments

Cash and short-term investments consist of cash in the bank, less outstanding cheques and short-term deposits with a maturity of less than three months.

Petroleum and Natural Gas Properties

Effective January 1, 2004, the Trust adopted the new Canadian accounting guideline for oil and gas accounting using the full cost method. Under this guideline all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges related to exploration and development activities.

In accordance with the new guideline, the Trust evaluates its oil and gas assets to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceed the carrying value of the oil and gas assets. If the carrying value of the oil and gas assets is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves and the lower of cost and market of unproved properties. The cash flows are estimated using the future product prices and costs and are discounted using the risk-free rate. The impact of the adoption of the new guideline is described in note 4.

Proceeds from the disposition of petroleum and natural gas properties are applied against capitalized costs except for dispositions that would change the rate of depletion and depreciation by 20 percent or more, in which case a gain or loss would be recorded.

Depletion and Depreciation

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit-of-production method based on estimated gross proved reserves of petroleum and natural gas as determined by independent engineers. For purposes of this calculation, reserves and production are converted to equivalent units of oil based on relative energy content of six thousand cubic feet of gas to one barrel of oil. Costs of significant unproved properties, net of impairments, are excluded from the depletion and depreciation calculation.

Other assets, which is comprised of office equipment and furniture and fixtures, are recorded at cost and are depreciated over their useful life on a declining balance basis at 20 percent.

Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the new Canadian accounting standard for asset retirement obligations. Under this new standard, the Trust records a liability for the fair value of legal obligations associated with the retirement of long-lived tangible assets in the period in which they are incurred, normally when the asset is purchased or developed. On recognition of the liability there is a corresponding increase in the carrying amount of the related asset known as the asset retirement cost, which is depleted on a unit-of-production basis over the life of the reserves. The liability is adjusted each reporting period to reflect the passage of time, with the accretion charged to earnings, and for revisions to the estimated future cash flows. Actual costs incurred upon settlement of the obligations are charged against the liability. The impact of the adoption of the new standard is described in note 6.

Goodwill

Goodwill is tested for impairment on an annual basis in the fourth quarter. If indications of impairment are present, a loss would be charged to earnings for the amount that the carrying value of goodwill exceeds its fair value.

Hedging

The Trust uses derivative financial instruments from time to time to hedge its exposure to commodity price and foreign exchange fluctuations. The Trust does not enter into derivative financial instruments for trading or speculative purposes.

The derivative financial instruments are initiated within the guidelines of the Trust's risk management policy. This includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Trust's firm commitment or forecasted transaction and the underlying basis of the instrument, such as commodity price or foreign exchange rate, correlates highly with the Trust's exposure.

The Trust enters into hedges of its exposure to petroleum and natural gas commodity prices by entering into crude oil and natural gas swap contracts, options or collars, when it is deemed appropriate. These derivative contracts, accounted for as hedges, are not recognized on the balance sheet. Realized gains and losses on these contracts are recognized in petroleum and natural gas revenue and cash flows in the same period in which the revenues associated with the hedged transaction are recognized. Premiums paid or received are deferred and amortized to earnings over the term of the contract.

The Trust may enter into foreign exchange forward contracts to hedge anticipated U.S. dollar denominated petroleum and natural gas sales. These derivatives, accounted for as hedges, are not recognized on the balance sheet. The gains and losses on these derivatives are recognized as an adjustment to petroleum and natural gas revenues when the revenue is recognized.

Gains and losses resulting from changes in the fair value of derivative contracts that do not qualify for hedge accounting are recognized in earnings when those changes occur.

Effective January 1, 2004, the Trust adopted the new Canadian accounting guideline for hedging relationships. The guideline describes the conditions necessary for a transaction to qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting and the requirements to assess the effectiveness of hedging relationships. Also early in 2004, an amended accounting abstract became effective which requires financial instruments that are not designated as hedges to be recorded at fair value on the balance sheet with changes in fair value recognized in earnings. The adoption of the guideline and amended abstract had no impact on the Trust's financial position as at January 1, 2004.

Revenue Recognition

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

Transportation Expense

Effective January 1, 2004, and consistent with the adoption of the new Canadian accounting standard for generally accepted accounting principles, transportation costs are presented as an expense in the consolidated statements of earnings and accumulated earnings. The new standard defines the sources of GAAP and effectively eliminates industry practice as a source of GAAP. In 2003, as was industry practice, transportation expenses were netted off revenue and have been reclassified to conform to the presentation adopted in 2004. In British Columbia, there is an infrastructure in place that enables gas producers to avoid facility construction in exchange for regulated gathering, processing and transmission fees. This all-in charge is included in transportation expenses.

Income Taxes

The Trust follows the liability method of accounting for income taxes. Temporary differences arising from the differences between the tax basis of an asset or liability and its carrying amount on the balance sheet are used to calculate future income tax assets or liabilities. Future income tax assets or liabilities are calculated using tax rates anticipated to apply in the periods that the temporary differences are expected to reverse.

Unit Based Compensation

The Trust has established a Performance Unit Incentive Plan (the "Plan") for employees, directors and long-term consultants who otherwise meet the definition of an employee of the Trust. The Trust uses the fair value method for valuing unit based compensation and unit option grants. Under this method, compensation cost attributable to performance units granted is measured at the fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the settlement of the Plan, the previously recognized value in contributed surplus will be recorded as an increase to Unitholders' capital. On December 2, 2004 the Trust granted performance units that will vest on July 2, 2007 the details of which are described in note 7.

The Trust has not incorporated an estimated forfeiture rate for performance units that will not vest, rather, the Trust accounts for actual forfeitures as they occur.

Per Unit Information

Per unit information is calculated on the basis of the weighted average number of trust units and issuable exchangeable shares outstanding during the fiscal year. Diluted per unit information reflects the potential dilution that could occur if securities or other contracts to issue units were exercised or converted to units. Diluted per unit information is calculated using the treasury stock method that assumes any proceeds received by the Trust upon the exercise of in-the-money unit options plus the unamortized unit compensation cost would be used to buy back trust units at the average market price for the period.

Exchangeable Shares

On January 19, 2005, a new accounting abstract, "Exchangeable Securities Issued by Subsidiaries of Income Trusts", was issued effective for financial statements issued after the date of issue of this abstract. The abstract specifies that exchangeable shares are presented as equity only if certain circumstances exist, otherwise they are classified as non-controlling interest. The adoption of this abstract had no impact on the Trust's financial position or results of operations for the year ended December 31, 2004.

2. ACQUISITION OF CEQUEL ENERGY INC.

On July 2, 2004, pursuant to the Arrangement, Progress Energy Ltd. and Cequel amalgamated to create the Trust and two exploration-focused companies, ProEx and Cyries. The transaction was accounted for as a business combination with Progress being deemed the acquirer of Cequel, net of the assets acquired by Cyries. The consideration offered was 0.695 of a trust unit for each Cequel share resulting in 45,911,352 trust units and exchangeable shares being issued. The value of the transaction was $646.2 million, including $1.6 million of acquisition costs. The results of Cequel have been included in these consolidated financial statements from the date of acquisition. The transaction has been allocated as follows:

Net assets acquired [1]	
Property, plant and equipment	387,276
Goodwill	405,655
Working capital deficiency	(11,079)
Bank debt	(44,473)
Asset retirement obligations	(6,670)
Future income taxes	(84,471)
Total net assets acquired	646,238
Consideration	
Trust units issued	518,272
Exchangeable shares issued	126,369
Acquisition costs	1,597
Total purchase price	646,238

[1] *Pursuant to the Arrangement, assets acquired by Cyries from Cequel were accounted for prior to Progress acquiring Cequel. As a result, the acquisition of Cequel is net of the assets acquired by Cyries.*

The above amounts are estimates, which were made by management at the time of the Arrangement based on information currently available. Amendments may be made to these amounts as values subject to estimate are finalized.

3. PLAN OF ARRANGEMENT

Under the Arrangement, Progress Energy Ltd. transferred to ProEx certain prospective natural gas weighted assets and undeveloped land at their net book value. A future tax liability has been recorded as a result of transferring tax pools of $32.5 million, which were in excess of the net book value of $24.6 million. The details are as follows:

	2004
Petroleum and natural gas properties	**26,377**
Future income tax assets	**2,768**
Asset retirement obligations	**(1,813)**
Total assets transferred	**27,332**
Bank indebtedness assumed	**(10,000)**
Net assets transferred and reduction in accumulated earnings	**17,332**
Plan of arrangement costs, net of income tax benefit of $7,101	**12,844**
Total Plan of Arrangement and reduction in accumulated earnings	**30,176**

In accordance with the Arrangement, all outstanding stock options of Progress Energy Ltd. vested, Progress Energy Ltd. accepted the holders' put right thereby settling the options for cash in the amount of $21.9 million. The after tax value of the cash settlement, net of $3.0 million of contributed surplus relating to the options, resulted in a charge of $12.8 million to accumulated earnings. As a result, the remaining unamortized stock based compensation cost relating to options granted after 2002 of $2.5 million was charged to earnings. The Trust also incurred $0.8 million of severance costs, which together with the stock based compensation expense, have been included in plan of arrangement expense on the consolidated statement of earnings and accumulated earnings.

4. PROPERTY, PLANT AND EQUIPMENT

	2004	(Restated) 2003
Property, plant and equipment	**752,846**	286,845
Accumulated depletion and depreciation	**(119,231)**	(61,726)
Property, plant and equipment	**633,615**	225,119

The calculation of 2004 depletion and depreciation expense included an estimated $18.1 million for future development costs associated with proved undeveloped reserves and excluded $22.8 million for the estimated future net realizable value of production equipment and facilities and $71.6 million for the estimated value of unproven properties. Depletion and depreciation expense for the year ended December 31, 2004 was $57.5 million (2003 – $25.1 million).

Included in the Trust's property, plant and equipment balance is $9.8 million, net of accumulated depletion, related to asset retirement obligations ($14.4 million before accumulated depletion) (Refer to note 6).

The Trust capitalized approximately $1.5 million of geological and geophysical expenses associated with the exploration and development of capital assets during the year ended December 31, 2004 (2003 – $0.9 million).

Adoption of the new guideline for oil and gas accounting using the full cost method, as outlined in note 1, had no effect on the Trust's financial statements, based on the ceiling test prepared on initial adoption on January 1, 2004 using commodity price forecasts of the Trust's independent reserve engineers adjusted for differentials specific to the Trust's reserves.

The Trust performed a ceiling test calculation at December 31, 2004 resulting in the undiscounted cash flows from proved reserves and the lower of cost and market of unproved properties exceeding the carrying value of oil and gas assets. The following table summarizes the future benchmark prices the Trust used in the ceiling test:

	Crude Oil		Natural Gas
	West Texas Intermediate *(Cdn$/bbl)* [1]	Edmonton Par Price *(Cdn$/bbl)*	AECO Gas Price *(Cdn$/mmbtu)*
2005	42.00	50.25	6.60
2006	40.00	47.75	6.35
2007	38.00	45.50	6.15
2008	36.00	43.25	6.00
2009	34.00	40.75	6.00
2010 – 2015	33.50	40.00	6.10
Thereafter [2]	2%	2%	2%

[1] Future prices incorporated a $0.82 US/Cdn exchange rate.

[2] Percentage change of 2% represents the change in future prices each year after 2015 to the end of the reserve life.

5. BANK DEBT

	2004	2003
Direct advances	**1,222**	10,158
Banker's acceptances	**132,500**	34,915
Total bank debt	**133,722**	45,073

In conjunction with the Arrangement, the Trust entered into new credit facilities with a syndicate of banks and currently has a $200 million extendible revolving term credit facility and a $15 million working capital credit facility. The facilities are available on a revolving basis for a period of at least 364 days until May 31, 2005, and such initial term out date may be extended for further 364 day periods at the request of the Trust, subject to approval by the banks. Following the term out date, the facilities will be available on a non-revolving basis for a one year term, at which time the facilities would be due and payable. Various borrowing options are available under the facilities including prime rate based advances and banker's acceptance loans. Average cost of borrowing under these facilities in 2004 was 3.5 percent (2003 – 4.0 percent). The credit facilities are secured by a $500 million fixed and floating charge debenture on the assets of the Trust and by a guarantee and subordination provided by Progress in respect of the Trust's obligations. The $215 million borrowing base is subject to semi-annual review by the banks.

6. ASSET RETIREMENT OBLIGATIONS

The new accounting standard, as outlined in note 1, was adopted retroactively with restatement of prior periods presented for comparative purposes. The effect of the adoption on previously reported amounts is presented below as increases (decreases):

Balance Sheet	2003
Asset retirement costs, included in property, plant and equipment	5,477
Asset retirement obligations	11,778
Site restoration and abandonment liability	(3,965)
Future income taxes	(826)
Accumulated earnings	(1,510)

Income Statement	2003
Depletion, depreciation and accretion	379
Future income taxes	(134)
Net earnings	(245)
Net earnings per unit	
Basic	$ (0.01)
Diluted	$ (0.01)

Asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, the estimated costs to abandon and reclaim the wells and facilities and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows required to settle the asset retirement obligations is approximately $42.2 million which will be incurred over the next 43 years with the majority of costs incurred between 2009 and 2020. A credit adjusted risk-free rate of eight percent was used to calculate the fair value of the asset retirement obligations.

The following reconciles the Trust's asset retirement obligations:

	2004	2003
Balance, beginning of year	**11,778**	11,987
Liabilities incurred	**703**	1,732
Liabilities settled	**(358)**	(225)
Acquisitions *(Note 3)*	**6,670**	–
Dispositions	**(3,811)**	(2,687)
Accretion expense	**1,083**	971
Balance, end of year	**16,065**	11,778

7. UNITHOLDERS' CAPITAL

The Trust Indenture provides that an unlimited number of trust units may be authorized and issued. Each trust unit is transferable, carries the right to one vote and represents an equal undivided beneficial interest in any distributions from the Trust and in the assets of the Trust in the event of termination or winding-up of the Trust. All trust units are of the same class with equal rights and privileges.

(a) Trust Units of Progress Energy Trust

	2004		2003	
	Number	Amount	Number	Amount
Trust Units				
Balance, beginning of year	–	–	–	–
Issued for common shares	28,238,061	81,869	–	–
Issued on Cequel acquisition *(Note 2)*	36,911,352	518,272	–	–
Issued for cash	250,003	2,993	–	–
Exchangeable shares converted	1,499,082	13,443	–	–
Unit issue costs	–	(1,998)	–	–
Balance, end of year	66,898,498	614,579	–	–

Redemption Right

Unitholders may redeem their trust units for cash at any time, up to a maximum value of $250,000 in any calendar month, by delivering their unit certificates to the Trustee, together with a properly completed notice requesting redemption. The redemption amount per trust unit will be the lesser of 90 percent of the simple average closing price of the trust units on the principal market on which they are traded for the 10 day trading period after the trust units have been validly tendered for the redemption and the closing market price of the trust units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or if there was no trade of the trust units on that date, the average of the last bid and ask prices of the trust units on that date.

(b) Exchangeable Shares

	2004		2003	
	Number	Amount	Number	Amount
Balance, beginning of year	–	–	–	–
Issued for common shares	6,999,994	20,300	–	–
Issued on Cequel acquisition *(Note 2)*	9,000,000	126,369	–	–
Exchanged for trust units	(1,466,488)	(13,443)	–	–
Balance, end of year	14,533,506	133,226	–	–

The exchangeable shares can be converted, at the option of the holder into trust units at any time and are listed on the Toronto Stock Exchange under the symbol PGE. If the number of exchangeable shares outstanding is less than 1,600,000, the Trust can elect to redeem the exchangeable shares for trust units or an amount in cash equal to the amount determined by multiplying the exchange ratio on the last business day prior to the redemption date by the current market price of a trust unit on the last business day prior to such redemption date. The number of trust units issued upon conversion is based on the exchange ratio in effect on the date of conversion. The exchange ratio is calculated monthly based on the five day weighted average trust unit trading price at the end of each month. The exchangeable shares are not eligible for cash distributions.

Retraction of Exchangeable Shares

Exchangeable shareholders may redeem their shares at any time by delivering their share certificates to the Trustee, together with a properly completed retraction request. The retraction price will be satisfied with trust units equal to the amount determined by multiplying the exchange ratio on the last business day prior to the retraction date by the number of exchangeable shares redeemed.

Redemption of Exchangeable Shares

On July 2, 2009 the exchangeable shares will be redeemed by the Trust unless the Board of Directors elect to extend the redemption period. The exchangeable shares will be redeemed by either issuing units or payment in cash for an amount equivalent to the value of the exchangeable shares at the current exchange ratio.

(c) Common Shares of Progress Energy Ltd.

	2004		2003	
	Number	**Amount**	Number	Amount
Common Shares				
Balance, beginning of year	**33,411,094**	**96,752**	30,911,781	74,477
Issued on exercise of stock options	**573,463**	**2,098**	499,313	1,729
For cash, pursuant to public offering	**–**	**–**	2,000,000	21,000
Issued on exercise of warrants	**1,253,498**	**3,322**	–	–
Exchanged for trust units	**(28,238,061)**	**(81,869)**	–	–
Exchanged for exchangeable shares	**(6,999,994)**	**(20,300)**	–	–
Share issue costs, net of tax of $1 (2003 – $447)		**(3)**		(730)
Balance, end of year	**–**	**–**	33,411,094	96,476
Warrants				
Balance, beginning of year	**1,253,498**	**276**	1,253,498	276
Warrants exercised	**(1,253,498)**	**(276)**	–	–
Balance, end of year	**–**	**–**	1,253,498	276
Total share capital	**–**	**–**	–	96,752

Net Earnings Per Unit

The following table summarizes the trust units and issuable exchangeable shares used in calculating net earnings per trust unit:

Weighted average trust units	**2004**	2003
Basic	**57,855,467**	31,492,045
Diluted	**58,998,486**	33,687,538

The reconciling items between the basic and diluted average trust units are performance units, stock options and warrants outstanding during the years ended December 31, 2004 and 2003.

Performance Unit Incentive Plan

In conjunction with the Arrangement the Trust established a Performance Unit Incentive Plan (the "Plan") for employees, directors, consultants and other service providers of the Trust or its subsidiary. The number of units reserved for issuance under the Plan shall not exceed five percent of the aggregate number of issued and outstanding units of the Trust and including the number of units which may be issued on the exchange of the outstanding exchangeable shares, which may be converted into trust units. Under the Plan, performance units ("PUIP's") shall be granted by the Board of Directors from time to time at its sole discretion. The PUIP's will vest on the third anniversary of the date of grant and actual payment will be determined based on the performance of the Trust relative to its peers. Performance factors range from 0.5 to 1.5 times the initial PUIP's granted. Over the three year term the PUIP's will attract distributions. The Trust expects to pay out the distribution portion in cash while the units earned will be issued from treasury.

On December 2, 2004 the Board of Directors granted 395,267 PUIP's retroactive to July 2, 2004. As a result, the fair value of the PUIP's granted of approximately $5.3 million will be amortized through general and administrative expenses over the vesting period as unit compensation cost with a corresponding increase to contributed surplus. Approximately $0.2 million was charged to general and administrative expenses in 2004. The distributions earned by the PUIP's of $0.3 million was charged to general and administrative expenses in 2004 with a corresponding increase to liabilities.

Stock Options

The following table sets forth a reconciliation of the stock option plan activity through to December 31, 2004:

	Number of options	Weighted average exercise price
Balance, beginning of year	3,205,938	5.91
Granted	17,000	12.75
Exercised	(573,463)	3.64
Settled for cash	(2,649,475)	6.44
Balance, end of year	–	–

Contributed Surplus

The following table reconciles the Trust's contributed surplus:

	2004	2003
Balance, beginning of year	**246**	–
Unit based compensation expense	**2,889**	246
Options exercised	**(10)**	–
Options settled for cash	**(2,954)**	–
Balance, end of year	**171**	246

8. TAXES

Tax Expense

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the unitholders. Cash distributions for the year ended December 31, 2004 totaled $55.7 million, reducing the Trust's expected future income tax expense and resulting in a recovery for the year ended December 31, 2004.

The combined provision for taxes in the consolidated statements of earnings and accumulated earnings reflect an effective tax rate which differs from the expected statutory tax rate. Differences were accounted for as follows:

	2004	(Restated) 2003
Earnings before taxes	**49,811**	30,937
Statutory income tax rate	**40.1%**	41.4%
Expected income taxes	**19,974**	12,808
Add (deduct)		
Net income of the Trust	**(22,337)**	–
Non-deductible crown charges	**13,365**	5,651
Resource allowance	**(9,337)**	(5,626)
Reduction in federal and provincial income tax rates	**(2,452)**	(4,151)
Attributed Canadian Royalty Income	**(1,945)**	–
Capital taxes	**1,454**	804
Other	**(1,488)**	206
	(2,766)	9,692

Future income taxes

The future income taxes liability at December 31 is comprised of the tax effect of temporary differences as follows:

	2004	(Restated) 2003
Property, plant and equipment	**120,211**	38,698
Asset retirement obligations	**(5,539)**	(4,165)
Commodity sales contracts	**(722)**	(968)
Share issue costs	**(1,216)**	(793)
Attributed Canadian Royalty Income	**(3,618)**	(498)
	109,116	32,274

As at December 31, 2004, the Trust's corporate subsidiary has tax pools of approximately $201.0 million (2003 – $127.2 million) available for deduction against future taxable income.

9. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital

	2004	2003
Accounts receivable	**6,920**	(1,684)
Prepaid expenses and deposits	**56**	43
Accounts payables	**7,078**	5,495
Current income taxes payable	**1,209**	–
Change in non-cash working capital	**15,263**	3,854
Relating to:		
Financing activities	**(268)**	268
Investing activities	**(6,440)**	4,904
Operating activities	**21,971**	(1.318)

Interest and taxes paid

	2004	2003
Interest paid	**3,725**	2,015
Income and other taxes paid	**573**	739

10. FINANCIAL INSTRUMENTS

Fair Value of Financial Instruments

The Trust's financial instruments recognized in the balance sheet consist of accounts receivable, accounts payable and accrued liabilities and bank debt. The fair value of these financial instruments approximate their carrying amounts due to their short terms to maturity or the indexed rate of interest on the bank debt.

Credit Risk

The Trust's accounts receivable are with customers and joint venture partners in the petroleum and natural gas business and are subject to normal credit risks. Concentration of credit risk is mitigated by marketing production to numerous purchasers under normal industry sale and payment terms. The Trust routinely assesses the financial strength of its customers.

The Trust may be exposed to certain losses in the event of non-performance by counter-parties to commodity price contracts. The Trust mitigates this risk by entering into transactions with counter-parties that provide sufficient collateral in support of payment or have investment grade credit ratings.

Interest Rate Risk

The Trust is exposed to interest rate risk to the extent that changes in market interest rates will impact Progress' debts that have a floating interest rate. The Trust had no interest rate swaps or hedges at December 31, 2004.

Commodity Price Contracts

The Trust has entered into several derivative financial instruments for natural gas for the purpose of protecting its cash flow from operations from the volatility of natural gas commodity prices. A natural gas collar was acquired in the Cequel acquisition valued at $1.7 million at June 30, 2004 and capitalized as part of the acquisition. Subsequent to the acquisition $1.7 million was charged to earnings for this collar.

Contracts outstanding in respect to financial instruments are as follows:

Contract	Volume	Pricing Point	Strike Price ($GJ)	Cost/ Premium	Term
Natural Gas					
Costless collar [1]	5,000 gj/d	AECO	Cdn$6.75 – Cdn$9.35	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	5,000 gj/d	AECO	Cdn$6.50 – Cdn$7.25	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	5,000 gj/d	AECO	Cdn$6.50 – Cdn$8.00	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	10,000 gj/d	AECO	Cdn$6.50 – Cdn$8.90	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	5,000 gj/d	AECO	Cdn$7.25 – Cdn$9.75	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	5,000 gj/d	AECO	Cdn$7.50 – Cdn$9.90	n/a	Nov 01/04 – Mar 31/05
Costless collar [1]	5,000 gj/d	AECO	Cdn$7.50 – Cdn$10.00	n/a	Nov 01/04 – Mar 31/05
Put option	5,000 gj/d	AECO	Cdn $8.50	Cdn$0.55/gj	Dec 1/04 – Mar 31/05
Costless collar [1,2]	30,000 gj/d	AECO	Cdn$6.00 – Cdn$7.50	n/a	April 01/05 – Oct 31/05

[1] *Collar strike price indicates minimum floor and maximum ceiling*

[2] *Contract entered into subsequent to December 31, 2004*

The estimated fair value of the natural gas collars that qualify for hedge accounting was a gain of $3.7 million as at December 31, 2004 and represents the amount the Trust would receive to terminate the contracts at December 31, 2004. These instruments have no carrying value recorded in the financial statements.

Commodity Sales Contract

The following physical gas sales contract was outstanding at December 31, 2004. This contract was acquired in conjunction with the acquisition of Campion Resources Ltd. on June 3, 2002, at which time the fair value of the contracts was a liability of $4.1 million. This value was recorded as a liability on June 3, 2002, and is being amortized over the life of the contract. At December 31, 2004 the unamortized liability remaining was $2.1 million.

Volume	Pricing Point	Progress Price	Term
1,000 gj/d	AECO	$2.06/gj in 2005 escalating at 2.5% annually	Jun 1/97 – Oct 31/08

11. SUBSEQUENT EVENT

On February 2, 2005 the Trust issued $100 million of 6.75 percent convertible unsecured subordinated debentures (the "Debentures") for net proceeds of $95.5 million. The Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $15.00 per trust unit. The Debentures mature on June 30, 2010 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

2004 SELECTED QUARTERLY INFORMATION

Progress Energy Trust

FINANCIAL HIGHLIGHTS

($ thousands except per unit amounts)	Three Months Ended 2004				Annual
	March 31	June 30	Sept. 30	Dec. 31	**2004**
INCOME STATEMENT					
Petroleum and natural gas revenue	30,812	38,811	68,299	76,767	**214,689**
Cash flow [1]	14,928	17,833	36,355	41,344	**110,460**
Per unit – basic	0.44	0.52	0.45	0.50	**1.91**
Per unit – diluted	0.41	0.49	0.45	0.50	**1.87**
Cash distributions declared [1]			27,670	28,035	**55,705**
Per unit			0.42	0.42	**0.84**
Net earnings	6,247	4,464	19,149	22,717	**52,577**
Per unit – basic	0.19	0.13	0.24	0.28	**0.91**
Per unit – diluted	0.17	0.12	0.24	0.28	**0.89**
PAYOUT RATIO					
Excluding exchangeable shares			76%	68%	
Including exchangeable shares			94%	83%	
BALANCE SHEET					
Capital Expenditures	43,702	16,615	12,112	33,993	**106,422**
Total debt	82,252	106,061	151,580	171,543	**171,543**
Unitholders' equity	140,224	134,816	754,600	749,452	**749,452**
Trust Units *(thousands except where otherwise stated)*					
Units outstanding, end of period	33,939	35,238	66,164	66,898	**66,898**
Units issuable for exchangeable shares			15,575	15,291	**15,291**
Total units outstanding and issuable for exchangeable shares, end of period	33,939	35,238	81,739	82,189	**82,189**
Weighted average units – diluted [2]	36,136	36,344	81,016	81,979	**58,998**
Exchange ratio, end of period			1.02188	1.05215	**1.05215**
Trust Unit Trading Statistics *($)*					
High			15.09	15.81	**15.81**
Low			12.12	12.95	**12.12**
Closing			14.95	13.52	**13.52**
Unit volume traded *(thousands)*			46,567	18,774	**65,341**
Exchangeable Shares Trading Statistics *($)*					
High			15.25	16.00	**16.00**
Low			13.00	13.55	**13.00**
Closing			15.25	14.11	**14.11**
Share volume traded *(thousands)*			272	95	**367**

[1] *See discussion in the Management's Discussion and Analysis.*

[2] *Includes exchangeable shares converted at the end of period exchange ratio.*

OPERATIONAL HIGHLIGHTS

	Three Months Ended 2004				Annual
	March 31	June 30	Sept. 30	Dec. 31	**2004**
DAILY PRODUCTION					
Natural gas *(mcfd)*	34,805	44,809	81,783	86,998	**62,221**
Crude oil *(bbls/d)*	2,227	2,160	2,475	2,475	**2,335**
Natural gas liquids *(bbls/d)*	329	325	1,197	1,394	**814**
Total daily production *(boe/d)*	8,357	9,953	17,302	18,368	**13,519**
AVERAGE REALIZED PRICES					
Natural gas – before hedging *($/mcf)*	6.66	7.17	6.94	7.32	**7.08**
Natural gas – after hedging *($/mcf)*	6.63	7.16	6.99	7.45	**7.13**
Crude oil – before hedging *($/bbl)*	44.15	48.75	53.35	55.69	**50.72**
Crude oil – after hedging *($/bbl)*	43.12	42.47	47.31	48.21	**45.44**
Natural gas liquids *($/bbl)*	36.33	43.40	45.09	48.24	**45.40**
HIGHLIGHTS *($/boe)*					
Weighted average sales price	40.52	42.85	42.91	45.42	**43.39**
Royalties	9.39	10.99	10.52	11.58	**10.80**
Operating expenses	6.36	6.15	5.81	5.55	**5.87**
Transportation expenses	2.99	2.98	1.98	1.96	**2.31**
Operating Netbacks	21.78	22.73	24.60	26.33	**24.41**
General and administrative expense	1.29	0.69	1.22	1.24	**1.14**
Interest and financing expenses	0.66	0.69	0.70	0.69	**0.69**
Depletion, depreciation and accretion	8.97	9.47	12.97	13.34	**11.84**
Plan of arrangement expenses	–	3.69	–	–	**0.67**
Net earnings before taxes	10.86	8.19	9.71	11.06	**10.07**
Capital taxes	0.24	0.20	0.35	0.31	**0.29**
Future income taxes (recovery)	2.41	3.06	(2.68)	(2.69)	**(0.85)**
Net Earnings	8.21	4.93	12.04	13.44	**10.63**
DRILLING RESULTS					
Gross	28	5	10	21	**64**
Net – natural gas	14.9	2.5	6.2	6.9	**30.5**
Net – crude oil	2.4	2.0	0.0	2.6	**7.0**
Success Rate *(percent)*	79	83	100	100	**89**

2003 SELECTED QUARTERLY INFORMATION

Progress Energy Trust

FINANCIAL HIGHLIGHTS

($ thousands except per unit amounts)	Three Months Ended 2003				Annual
	March 31	June 30	Sept. 30	Dec. 31	2003
INCOME STATEMENT					
Petroleum and natural gas revenue	29,446	24,784	24,939	28,370	107,539
Cash flow [1]	16,045	12,502	12,317	13,391	54,255
Per unit – basic	0.52	0.40	0.39	0.41	1.72
Per unit – diluted	0.48	0.37	0.37	0.39	1.61
Net earnings	6,470	6,835	3,647	4,293	21,245
Per unit – basic	0.21	0.22	0.12	0.13	0.68
Per unit – diluted	0.20	0.20	0.11	0.12	0.63
BALANCE SHEET					
Capital Expenditures	25,476	15,192	24,768	18,858	84,294
Total debt	56,318	57,748	70,167	55,433	55,433
Unitholders' equity	96,134	104,288	108,081	131,778	131,778
Trust Units *(thousands except where otherwise stated)*					
Units outstanding, end of period	30,937	31,320	31,327	33,411	33,411
Weighted average units – diluted	33,142	33,401	33,620	34,688	33,688

[1] *See discussion in the Management's Discussion and Analysis.*

OPERATIONAL HIGHLIGHTS

	Three Months Ended 2003				Annual
	March 31	June 30	Sept. 30	Dec. 31	2003
DAILY PRODUCTION					
Natural gas *(mcfd)*	26,830	26,873	28,736	33,237	28,936
Crude oil *(bbls/d)*	2,094	2,260	2,358	2,629	2,337
Natural gas liquids *(bbls/d)*	311	284	289	315	299
Total daily production *(boe/d)*	6,877	7,022	7,436	8,483	7,459
AVERAGE REALIZED PRICES					
Natural gas – before hedging *($/mcf)*	8.21	6.76	6.03	5.89	6.66
Natural gas – after hedging *($/mcf)*	8.30	6.80	6.07	6.04	6.74
Crude oil – before hedging *($/bbl)*	47.64	37.54	37.69	37.73	39.87
Crude oil – after hedging *($/bbl)*	44.17	36.84	37.14	36.35	38.40
Natural gas liquids *($/bbl)*	38.99	27.85	32.16	32.71	33.02
HIGHLIGHTS *($/boe)*					
Weighted average sales price	47.57	39.00	36.48	36.15	39.50
Royalties	10.35	8.15	7.19	7.76	8.30
Operating expenses	5.42	5.46	5.92	5.68	5.63
Transportation expenses	2.47	3.29	2.73	2.75	2.81
Operating Netbacks	29.33	22.10	20.64	19.96	22.76
General and administrative expense	1.39	1.06	1.03	1.80	1.34
Interest and financing expenses	0.67	0.86	0.85	0.68	0.77
Depletion, depreciation and accretion	9.14	9.38	9.26	9.39	9.29
Earnings before taxes	18.13	10.80	9.50	8.09	11.36
Capital taxes	0.31	0.29	0.30	0.29	0.30
Future income taxes	7.37	(0.19)	3.87	2.30	3.26
Net Earnings	10.45	10.70	5.33	5.50	7.80
DRILLING RESULTS					
Gross	23	7	28	18	76
Net – natural gas	8.0	6.0	16.6	12.8	43.4
Net – crude oil	6.0	–	4.0	2.0	12.0
Success Rate *(percent)*	75	86	87	88	84

CORPORATE INFORMATION

Progress Energy Trust

DIRECTORS

David D. Johnson
Executive Chairman
Progress Energy Ltd.
President & CEO
ProEx Energy Ltd.
Calgary, Alberta

Donald F. Archibald (1)(4)
Chairman & CEO
Cyries Energy Inc.
Calgary, Alberta

John A. Brussa (3)
Partner
Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Frederic C. Coles (1)(2)(4)
Independent Businessman
Calgary, Alberta

Howard Crone (2)(4)
Independent Businessman
Calgary, Alberta

Michael R. Culbert
President
Progress Energy Ltd.
Calgary, Alberta

Gary E. Perron (1)(3)
Senior Vice President and
Managing Director
BMO Nesbitt Burns
Calgary, Alberta

OFFICERS

David D. Johnson
Executive Chairman

Michael R. Culbert
President

Steven A. Allaire
Senior Vice President

Greg W. Kist
Vice President Investor Relations

Art A. MacNichol
Vice President Finance &
Chief Financial Officer

Neil H. Samis
Vice President Production

Daniel C. Topolinsky
Vice President Exploration

Gary R. Bugeaud
Secretary

CORPORATE OFFICE

1400, 440 – 2nd Avenue S.W.
Calgary, Alberta T2P 5E9
Telephone: (403) 216-2510
Fax: (403) 216-2514

(1) *Member of Audit Committee*
(2) *Member of Reserve Committee*
(3) *Member of Compensation Committee*
(4) *Member of Technical Services Committee*

Environment, Health and Safety, Corporate Governance and Nomination Matters are addressed by the entire Board of Directors

Progress Energy Trust is a Bronze Member of the CAPP Environmental Stewardship Program.

SHAREHOLDER INFORMATION

Progress Energy Trust

ANNUAL MEETING

The Annual Meeting of Unitholders will be held on Tuesday, April 26, 2005 at 3:30 p.m. in the Devonian Room, Calgary Petroleum Club, Calgary, Alberta.

ANNUAL INFORMATION FORM

Copies of the Annual Information Form are available to shareholders upon request.

WWW.PROGRESSENERGY.COM

Unitholders and interested investors are encouraged to visit our web site. Historical public disclosure documents (in PDF format), latest presentation material, press releases are all available. Filings also available at: www.sedar.com

TRUSTEE AND TRANSFER AGENT

Computershare Trust Company of Canada
Suite 600, 530 – 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Toll Free: 1-800-564-6253

CORPORATE GOVERNANCE

A system of corporate governance for the Trust has been established to provide the Board of Directors, management and unitholders of the Trust with effective governance. A more detailed discussion of corporate governance is available in the Information Circular for the Annual Meeting of Unitholders.

ESTIMATED RELEASE DATE OF QUARTERLY RESULTS

First Quarter	April 25, 2005
Second Quarter	July 26, 2005
Third Quarter	October 25, 2005

STOCK EXCHANGE

Toronto Stock Exchange trading symbols:
Trust Units – PGX.UN
Exchangeable Shares – PGE
Convertible Debentures – PGX.DB

SOLICITOR

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

AUDITOR

KPMG LLP
Calgary, Alberta

CONSULTING ENGINEERS

Gilbert Laustsen Jung
Associates Ltd.
Calgary, Alberta

INVESTOR RELATIONS

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Vice President, Investor Relations
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DESIGNED AND PRODUCED BY THE DESIGN CENTRE OF CANADA. PRINTED IN CANADA BY UNICOM GRAPHICS.

Progress Energy Trust
2004 Annual Report

Progress

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